COMMONWEALTH OF VIRGINIA
Department of Environmental Quality
Valley Regional Office

STATEMENT OF LEGAL AND FACTUAL BASIS

Virginia Electric & Power Company aka Dominion
Route 656 Fluvanna County, Virginia
Permit No. VRO40199

Title IV of the 1990 Clean Air Act Amendments required each state to develop a permit program to ensure that certain electrical generation facilities have federal Air Pollution Operating Permits, called Title IV Operating Permits. As required by 40 CFR Part 70, 9 VAC 5 Chapter 80, Article 3 and Chapter 140 of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution, Virginia Electric & Power Company has applied for a renewal of its Title IV Operating Permit for its Bremo Power Station electric generation facility. The Department has reviewed the application and has prepared a Federal Operating Permit. This permit is based upon Federal Clean Air Act Acid Rain permitting requirements of Title IV, federal operating permit requirements of Title V, and Chapter 80, Article 3 and Chapter 140 of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution.

Engineer/Permit Contact: [signature] Date: 12/30/13
Jeremy W. Funkhouser
(540)-574-7820

Air Permit Manager: Janardan R Pandey Date: 12/30/13
Janardan R. Pandey, P.E.

FACILITY INFORMATION

Permittee
Virginia Electric & Power Company aka Dominion
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Facility
Dominion - Bremo Power Station
1038 Bremo Road
Bremo Bluff Virginia 23022

Plant ID No. 51-065-0001

SOURCE DESCRIPTION

Facility Description: NAICS Code 221112 (Electric Power Generation)

The Bremo Power Station is a natural gas-fired electric power generating facility located in Fluvanna County, Virginia. The facility includes two wall-fired Babcock and Wilcox boilers rated at 920 and 1,684 million Btu per hour (MMBtu/hr) heat input capacity. The facility also includes a natural gas-fired auxiliary boiler, a natural gas-fired gas pipeline heater, and diesel fire pump.

The facility stopped using coal, distillate oil, and used oil as fuel for the boilers (Ref. 003 and 004) and formally shutdown the coal handling equipment at the facility under a mutual shutdown agreement with the DEQ, on September 19, 2013; after the termination of the use of coal, distillate oil, and used oil, the facility is no longer a major source of Hazardous Air Pollutants (HAPs) (i.e., the facility is considered an area source of HAPs). The facility is a Title V major source of nitrogen oxides (NO_x), and carbon monoxide (CO). The source is located in an attainment area for all pollutants and is a PSD major source. The facility is also subject to the Title IV Acid Rain regulations (9 VAC 5 Chapter 80, Article 3) and the Clean Air Interstate Rule (CAIR) (9 VAC 5 Chapter 140). The facility submitted the Phase II Acid Rain Permit Application for renewal of the Acid Rain Permit for the facility as part of the application. The facility also submitted the CAIR renewal application as part of the Title V permit renewal application.

COMPLIANCE STATUS

A full compliance evaluation of this facility, including a site visit, was last conducted on April 23, 2013. The facility was found to be out of compliance. The violation is carried over from a Notice of Violation (NOV) dated June 27, 2011 addressing opacity exceedances reported in the first quarter of 2011 for units 003 and 004. The issue is still being discussed between the DEQ

Central Office and Dominion. It is anticipated that the resolution of the violations will occur when the units (Ref. 003 and 004) begin using natural gas. No requirements from the NOV are included in the Title V permit.

On April 22, 2003, the U.S. Environmental Protection Agency (EPA) and the Department of Justice announced a settlement with Virginia Electric & Power Company (VEPCO) to resolve Clean Air Act violations at eight of VEPCO's coal-fired power plants including Bremo Power Station. The "Consent Decree" was entered by the United States District Court for the Eastern District Court of Virginia, Civil Action Nos. 03-CV-517-A and 03-CV-603-A, on October 10, 2003 between VEPCO and the United States, et al. The facility amended the minor NSR permit to convert the coal-fired portions of the Bremo Power Station to natural gas on May 24, 2013; however, certain requirements of the Consent Decree still apply to the facility. The Title V renewal permit includes requirements of the Consent Decree for Bremo Power Station that are at least as stringent as the terms of the Consent Decree.

CHANGES SINCE INITIAL PERMIT

On May 24, 2013, the minor NSR permit for the two large boilers (Ref. 003 and 004) was modified to convert the units (Ref. 003 and 004) from coal to natural gas. The permit modification also included: the shutdown of the coal and ash handling equipment; the replacement of the 8.7 MMBtu/hr auxiliary boiler with a 25 MMBtu/hr natural gas-fired auxiliary boiler; and the addition of a 4.277 MMBtu/hr natural gas-fired gas pipeline heater. The changes to the minor NSR permit are incorporated into the Title V permit.

In addition to the changes to the underlying minor NSR permit, the following changes have been made to the Federal Operating Permit:

- *Compliance Assurance Monitoring (CAM) Plan:* The two main boilers at Bremo (Ref. 003 and 004) are no longer subject to the requirements of 40 CFR Part 64.

- *Consent Order Requirements:* The April 22, 2003 Consent Decree between the United States and VEPCO was incorporated into the permit (Condition 22) with the fuel burning equipment requirements, and the Consent Order in its entirety is included as an attachment to the permit.

- *NOx Budget Trading Program:* The NOx Budget Trading Program (9 VAC 5-140-10) has been replaced by the Clean Air Interstate Rule (CAIR) (9 VAC 5-140-1010 *et seq.*). The requirements related to the NOx Budget Trading Program have been removed from the renewal permit.

- *Phase II Acid Rain Permit:* The Phase II Acid Rain Permit was incorporated into the permit, and as an attachment to the permit.

- *Clean Air Interstate Rule (CAIR) Requirements:* CAIR requirements are included as Condition 98 and as an attachment to the permit.

These changes are discussed in more detail in the sections below.

EMISSION UNIT AND CONTROL DEVICE IDENTIFICATION

The emissions units at this facility consist of the following:

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollutant Controlled	Applicable Permit Date
Fuel Burning Equipment							
001	001	Kewanee Package Boiler, Model #H3s-200-02-250 Distillate oil/propane-fired (1991)	8.693 MMBtu/hr	-	-	-	-
002	002	Solar Combustion Turbine Model T-351N-21 Kerosene/distillate oil-fired (1967)	5.24 MMBtu/hr	-	-	-	-
003	003	Babcock and Wilcox Natural Gas-fired boiler with low NOx burner and enhanced overfire air (1950)	920 MMBtu/hr	-	-	-	5/24/13
004	004	Babcock and Wilcox Natural Gas-fired boiler with low NOx burner and enhanced overfire air (1958)	1,684 MMBtu/hr	-	-	-	5/24/13
005	005	Auxiliary Boiler Natural gas-fired (2013)	25.0 MMBtu/hr	-	-	-	-

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollutant Controlled	Applicable Permit Date
Reciprocating Internal Combustion Engines							
007	007	Diesel Fire Pump	150 HP	-	-	-	-

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.

EMISSIONS INVENTORY

Annual emissions summarized in the following table are derived in part from the 2012 CEDS emission report and DEQ spreadsheets. A copy of the report and spreadsheets are attached as Attachment A.

2012 Pollutant Emissions (Plantwide Total)	
Pollutant	Tons Emitted
Criteria Pollutants	
PM-10	163.95
PM-2.5	10.00
VOC	4.74
NO_x	856.51
SO_2	2,950.64
CO	40.09
Lead (also a HAP)	0.027
Hazardous Air Pollutants (HAPs) *	
Hydrogen Fluoride	11.71
Hydrochloric Acid	93.66
Arsenic	0.13
Beryllium	0.02
Cadmium	0.01
Chromium Compounds	0.27
Manganese Compounds	0.30
Mercury	0.003
Nickel Compounds	0.22
POM	0.0004

*calculated from DEQ spreadsheets.

These emissions are primarily from the use of coal in the boilers (003 and 004). The use of coal, distillate oil, and used oil in Boilers 003 and 004 was terminated on September 19, 2013; the facility intends to convert the boilers to natural gas in 2014.

EMISSION UNIT APPLICABLE REQUIREMENTS

Fuel Burning Equipment Units: 001, 002, 003, 004, and 005

Limitations

The following limitations are state BACT requirements from the minor NSR permit issued on 5/24/13. The following limitations are specific for boilers 003 and 004. The condition numbers below are from the NSR permit; a copy of the permit is enclosed in Attachment B.

Condition 2:	NOx emissions from the boilers (Ref. 003 and 004) shall be controlled by low NO_x burners with enhanced overfire air, good combustion practices, operator training and proper emissions unit design, construction and maintenance.
Condition 3:	Carbon monoxide (CO) and volatile organic compound (VOC) emissions from the boilers (Ref. 003 and 004) shall be controlled by enhanced overfire air, good combustion practices, operator training and proper emissions unit design, construction and maintenance.
Condition 5:	The condition establishes the approved fuel for the boilers (Ref. 003 and 004) is natural gas.
Condition 6:	The condition establishes the combined natural gas fuel throughput for the two boilers (Ref. 003 and 004).
Condition 7:	The condition establishes the short-term emission limitations for Boiler 003.
Condition 8:	The condition establishes the short-term emission limitations for Boiler 004.
Condition 9:	The condition establishes the combined annual emission limitations for Boilers 003 and 004.
Condition 10:	The condition establishes the definitions of periods of startup and shutdown. The NOx and CO short-term emissions limits contained in Conditions 7 and 8 (of the NSR permit) apply at all times except during periods of startup and shutdown.
Condition 11:	The condition establishes the annual emission limitations in Condition 9 (of the NSR permit) is a compliance cap, imposed for the purpose of limiting the potential to emit carbon monoxide so as

to avoid permitting applicability under 9 VAC 5 Chapter 80 Article 8 (9 VAC 5-80-1605 *et seq.*) related to the conversion of the boilers from coal to natural gas.

Condition 12: Visible emissions from each boiler (Ref. 003 and 004) stack shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).

Condition 28: The condition establishes that at all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

In addition to the requirements from the minor NSR permit, the following requirement from 40 CFR 60 Subpart Dc has been added to the Title V permit for the natural gas-fired auxiliary boiler (Ref. 005) (condition number refers to the Title V permit):

Condition 19: Except where this permit is more restrictive, the natural-gas auxiliary boiler (Ref. 005) shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc.

The Kewanee package boiler (Ref. 001) is subject to the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63 Subpart JJJJJJ. The following requirements are established for the distillate oil and propane-fired boiler (Ref. 001), in accordance with 40 CFR 63 Subpart JJJJJJ (condition numbers refer to the Title V permit):

Condition 20: Except where this permit is more restrictive, the distillate oil and propane-fired boiler (Ref. 001) shall be operated in compliance with the requirements of 40 CFR 63, Subpart JJJJJJ no later than March 21, 2014.

Condition 21: The condition establishes the tune-up requirements for the boiler (Ref. 001).

The boiler (Ref. 001) is an affected existing source that burns distillate oil and liquefied propane. The facility intends to permanently shut down the boiler prior to the March 21, 2014 MACT compliance date. However, if the boiler is in operation after the March 21, 2014 compliance date, the boiler must meet the requirements of the MACT. In accordance with §63.11201 (a), there are no emission limitations for existing oil or gas fired boilers. The facility is required to meet the work practice standards and management practices contained in §63.11201(b) and Table 2 to the subpart after March 21, 2014 if the boiler is in operation. The tune-up requirements for the boiler (Ref. 001) are specified in §63.11223(b) and Condition 21 of the permit.

The following Virginia Administrative Codes that have specific emission requirements have been determined to be applicable:

9 VAC 5-40-900, Emission Standards for Fuel Burning Equipment – Standard for Particulate Matter – applies to all fuel burning equipment installations within a stationary source in operation prior to October 5, 1979; Unit 002 is considered a fuel burning unit installed and in operation prior to October 5, 1979. The following allowable emissions for unit 002, in pounds of particulate per million BTU input, are calculated in accordance with 9 VAC 5-40-900 A.1.a, for installations less than 10 MMBtu/hr:

Maximum Allowable Emission Rate (E) = 0.6 lb/MMBtu

Therefore allowable particulate emissions for Unit 002 are:

Maximum Allowable Emissions = 0.6 lb/MMBtu x 5.24 MMBtu/hr = 3.14 lb/hr

This rule also applies to Unit 001. The maximum allowable emission ratio for units with a capacity of less than 10 million BTU/hr is 0.6 pounds of particulate per million BTU input. Therefore:

Maximum Allowable Emissions = 0.6 lb/MMBtu x 8.693 MMBtu/hr = 5.22 lbs/hr

9 VAC 5-40-900 is no longer applicable to boilers 003 and 004. The boilers were modified in 2013, and the minor NSR permit, dated 5/24/13, provides more stringent requirements for boilers 003 and 004.

9 VAC 5-40-930, Emission Standards for Fuel Burning Equipment – Standard for Sulfur Dioxide – Allowable emissions, in pounds of sulfur dioxide per hour, are calculated using the following formula:

Maximum Allowable Emissions (S) = 2.64K

where K is the allowable heat input at total capacity in MMBtu/hr. Therefore:

Unit 001	S = 2.64 x 8.693 = 22.95 lbs/hr
Unit 002	S = 2.64 x 5.24 = 13.83 lbs/hr

The minor NSR permit, dated 5/24/13, provides more stringent requirements for boilers 003 and 004.

9 VAC 5-50-80, Standard for Visible Emissions – Visible emission limit for new and modified units shall not exceed 20% opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 30% opacity applies to Unit 001 and Unit 005.

9 VAC 5-40-80 and 9 VAC 5-40-940, Standard for Visible Emissions – Visible emission limit for existing units shall not exceed 20% opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 60% opacity applies to Unit 002.

The minor NSR permit, dated 5/24/13, provides more stringent requirements for boilers 003 and 004.

Consent Decree

The facility is subject to a Consent Decree entered by the United States District Court for the Eastern District of Virginia, Civil Action Nos. 03-CV-517-A and 03-CV-603-A, filed on October 10, 2003 between Virginia Electric & Power Company and the United States, et al (the "Consent Decree"). The Consent Decree, as such might be amended or modified in accordance with its terms, is incorporated in its entirety into this permit by reference and is provided as Attachment C to the permit.

The following requirement is established in the Title V permit (Condition number below refers to the Title V permit):

Condition 22: The condition establishes the basis and applicability of the Consent Decree. The Consent Decree, as such might be amended or modified in accordance with its terms, is incorporated in its entirety into this permit by reference and is attached as Attachment C. The permittee shall comply with the terms and conditions of the Consent Decree that relate to the operation of Bremo Power Station exclusively and such compliance shall be determined exclusively by reference to the terms and conditions of the Decree. Whenever any conflict or ambiguity arises between the Consent Decree and this permit, the terms and conditions of the Consent Decree will control. The limitations, monitoring, recordkeeping, and reporting requirements include applicable requirements from the Consent Decree.

Monitoring and Recordkeeping

Emission Units 001 and 002

Actual emissions from the operation of units 001 and 002 will be calculated using the following equation:

$$E = F \times O$$

Where:

E = Emission rate (lb/time period)
F = Pollutant specific emission factors provided below
O = Rated capacity of the unit (1000 gal/hr or mmBTU/hr)

Emission Factors for Unit 001

Emission Unit 001		
Pollutant	**LPG (lb/1000 gal)**	**Distillate Oil (lb/1000 gal)**
PM/PM-10	0.6	3.3
SO_2	1.5	71

Emission Factors for Unit 002

Emission Unit 002		
Pollutant	**Distillate Oil (lb/MMBtu)**	**Kerosene (lb/MMBtu)**
PM/PM-10	0.31	0.012
SO_2	0.29	0.505

Emission factors for SO_2 for Unit 001 while firing distillate oil are taken from AP-42 Chapter 1.3, Table 1.3-1, assuming a fuel sulfur content of 0.5 percent; emission factors for PM/PM-10 for Unit 001 while firing distillate oil are taken from AP-42 Chapter 1.3, Tables 1.3-1 and 1.3-2. Emission factors for SO_2 and PM/PM-10 for Unit 001 while firing LPG are taken from AP-42, Chapter 1.5, Table 1.5-1; the SO_2 emission factor assumes a fuel sulfur content of 15 gr/100 ft^3.

Emission factors for SO_2 and PM/PM-10 for Unit 002 while firing distillate oil were taken from AP-42, Chapter 3.3, Table 3.3-1. Emission factors for SO_2 and PM/PM-10 for Unit 002 while firing kerosene were taken from the EPA FIRE database, based on the Source Classification Code 20100901. The SO_2 emission factor assumes a sulfur content of 0.5 percent.

Calculations have been included in Attachment C to demonstrate that the emission limits can be met for 001 and 002. Visible emissions observations on the exhaust stack of units 001 and 002 are required according to the schedule in Condition 28. If during the inspection, visible emissions are observed, an EPA, Method 9 visible emission evaluation is required.

In addition to the emission limitations and visible emission limits, the Kewanee package boiler (Ref. 001) will also subject to the boiler MACT, if the unit remains in operation after March 21, 2014, as mentioned above. The boiler MACT (40 CFR 63 Subpart JJJJJ) establishes work practice standards and management practices for the Kewanee package boiler (Ref. 001). Compliance with the requirements to conduct an initial tune-up of the Kewanee package boiler (Ref. 001), in addition to biennial tune-up, is established through the recordkeeping requirements of 40 CFR 63.11225 and Condition 29. The facility is required to keep records of: each notification and report, including all documentation supporting any Initial Notification or Notification of Compliance Status, submitted to comply with the requirements of 40 CFR 63 Subpart JJJJJ; records to document conformance with work practices, and management practices required by 40 CFR 63.11214 and 40 CFR 63.11223; and records of boiler (Ref. 001) malfunctions and any corrective actions taken in accordance with 40 CFR 63.11225(c)(4) and (5).

The recordkeeping requirements, in addition to the actual emission calculations discussed above, provide a means of demonstrating continuous compliance with the limitations established for Units 001 and 002 in the Title V permit.

<u>Emission Units 003 and 004</u>
The following monitoring and recordkeeping requirements are from the NSR permit issued on 5/24/13; the requirements refer to boilers 003 and 004; condition numbers refer to the minor NSR permit:

Condition 13:	Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO_x (measured as NO_2) and CO, in lb/MMBtu from each boiler (Ref. 003 and 004).
Condition 14:	Performance evaluations of the NO_x and CO continuous monitoring systems shall be conducted in accordance with 40 CFR 60, Appendix B, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter.
Condition 15:	A CEMS quality control program which is equivalent to the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix F or Part 75 shall be implemented for all continuous monitoring systems

The requirement for the installation and use of CEMs for NOx and CO provides a means of demonstrating continuous compliance with the hourly and annual NOx and CO emission limitations for boilers 003 and 004. The facility is required to keep records of all CEMS calibrations and calibration checks, percent operating time, and excess emissions.

The hourly emission limits established for boiler 003 and 004, for all other criteria pollutants (particulate matter, SO_2, and VOC) are based on the rated capacities and rated hourly fuel consumption of each boiler. The NOx and CO emission limitations were also established based on the rated capacities and rated hourly fuel consumption of each boiler. The following equation and emissions factors will be used to determine actual emissions from the operation of each boiler 003 and 004:

$$E = F \times N$$

Where:

E = emission rate (lb/time period)
F = pollutant specific emission factor, provided below
N = fuel consumed (million ft^3/time)

Natural Gas Emission Factors – Boilers 003 and 004

Pollutant	Emission Factor		Source of DEQ Factor
	003	004	
PM (lbs/mmcuft)	7.6	7.6	Vendor Supplied Data
PM10 (lbs/mmcuft)	7.6	7.6	Vendor Supplied Data
PM2.5 (lbs/mmcuft)	7.6	7.6	Vendor Supplied Data
SO_2 (lbs/mmcuft)	0.9	0.9	Vendor Supplied Data
VOC (lbs/mmcuft)	4.1	4.1	Vendor Supplied Data
NOx (lbs/mmcuft)	165.2	154.9	Vendor Supplied Data
CO (lbs/mmcuft)	62.0	62.0	Vendor Supplied Data

Calculations showing the emission factors and emission calculations are available in Attachment B.

Annual emissions for the boilers are calculated based on the maximum fuel throughput contained in the NSR permit. Condition 6 of the NSR (dated 5/24/13) limits the total fuel throughput for the boilers (Ref. 003 and 004). Monthly recordkeeping demonstrating compliance with the fuel throughput limits provides reasonable assurance of compliance with the annual criteria pollutant emission limits, satisfying the periodic monitoring requirement. In addition to the records of the annual throughput of natural gas, the facility is also required to keep records of emission calculations sufficient to verify compliance with the annual emission limitations. Emission factors used to demonstrate compliance with PM, PM-10, PM-2.5, SO2 and VOC emissions are shown above; CEMS data provides a means of demonstrating compliance with the NOx and CO emission limitations.

In addition to the monitoring and recordkeeping requirements from the NSR discussed above, Condition 26 of the Title V permit requires the facility to conduct monthly visible emission observations of each stack (003 and 004). If no visible emissions are observed, a note to that effect should be recorded. However, if visible emissions are observed, a visible emissions evaluation (VEE) shall be conducted using 40 CFR Part 60, Appendix A, Method 9 for a period of not less than six minutes. If any of the observations exceed the applicable opacity limit, the observation period shall continue until 60 minutes of observations have been completed. If visible emissions inspections conducted during four consecutive operating months show no visible emissions, the permittee may reduce the monitoring frequency from monthly to quarterly for that emission unit. The requirement to conduct visible emission observations satisfies the periodic monitoring requirement establishing compliance with visible emission limitation. Condition 27 of the Title V permit requires the facility to take corrective actions if the VEE indicates the visible emissions exceed the visible emission limitation. The facility is required to keep records of all monthly visible inspections and the results of all VEEs for each boiler stack, as well as written operating procedures, scheduled and unscheduled maintenance and operator training. The required recordkeeping establishes a means of demonstrating compliance with the visible emission limitations for boilers 003 and 004.

Emission Unit 005
The boiler (Ref. 005) is subject to NSPS Subpart Dc; however, since the unit is a 25 MMBtu/hr natural-gas fired boiler, it is subject only to monitoring, recordkeeping, and notification requirements. Condition 5 of the Title V permit established the approved fuel; the recordkeeping requirement of Condition 29.b establishes compliance with the NSPS Subpart Dc requirements to monitor fuel usage, found in §60.48c (g). The notification requirements are discussed in the Reporting section below.

Since the unit (Ref. 005) only burns natural gas, the visible emission limitations established in 9 VAC 5-50-80 can easily be met on a continuous basis; no initial visible emission evaluation are required for the unit. Periodic monitoring is satisfied by keeping records that only natural gas is burned.

Compliance with the visible emission limitation for emission unit 005 may also be determined through visible emission evaluations, conducted upon request by the Department and/or the EPA. The facility is required to keep all records of performance tests and visible emissions evaluations as established in Condition 29.k of the Title V permit. Records of the visible emissions evaluations also provide a means of demonstrating compliance with the visible emission limitation in the permit. Requirements for testing are discussed below.

Testing

The following testing requirements are from the NSR issued on 5/24/13; condition numbers refer to the minor NSR permit for units 003 and 004:

Condition 4: The permitted facility shall be constructed so as to allow for emissions testing at any time using appropriate methods.

Condition 18: The permittee shall conduct initial performance tests for PM-10, PM-2.5, nitrogen oxides (measured as NO_2), CO, and VOC for each boiler (Ref. 003 and 004). The tests shall be performed on each boiler (Ref. 003 and 004) to determine compliance with the hourly emission limits.

Condition 19: Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall also be conducted by the permittee on each boiler (Ref. 003 and 004).

Condition 20: Upon request by the DEQ, the permittee shall conduct additional stack tests to demonstrate compliance with the emission limits contained in this permit. This condition has been modified to include all fuel burning units.

Condition 21: Upon request by the DEQ, the permittee shall conduct additional Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9 to demonstrate compliance with the visible emission limits contained in the permit. This condition has been modified to include all fuel burning units.

The requirements allowing for additional stack testing or visible emission evaluations were expanded to include all fuel burning units and ensure the Department and EPA have authority to require testing not included in this permit if necessary to determine compliance with an emission limit or standard.

In addition to the testing requirements from the minor NSR permit (dated 5/24/13), the following testing condition is established in the Title V permit (condition numbers refer to the Title V permit):

Condition 35: If testing is conducted in addition to the monitoring specified in this permit, the permittee shall use the appropriate method(s) in accordance with procedures approved by the DEQ.

Compliance Assurance Monitoring (CAM)

The two main boilers at the Bremo Power Station (003 and 004) are no longer subject to the requirements of 40 CFR Part 64, Compliance Assurance Monitoring (CAM). The boilers (Ref. 003 and 004) are each equipped with CEMS for NOx and CO, which meet the definition of Continuous Compliance Determination Method in 40 CFR 64.1, therefore the units are exempt from CAM under 40 CFR 64.2 (b)(1)(iv).

CAM is not applicable to emission units 001, 002, or 005 since each unit does not use a control device to meet the emission standards.

Reporting

The following reporting requirements are from the NSR issued on 5/24/13; condition numbers refer to the minor NSR permit:

Condition 16:	The permittee shall furnish written reports to the DEQ of excess emissions from any process monitored by a continuous monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter.
Condition 22:	The condition outlines the notifications required for the modification to burn natural gas for boilers 003 and 004.
Condition 26:	The condition requires the facility to furnish notification of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour.

In addition to the reporting requirements from the minor NSR permit (dated 5/24/13), the following reporting requirement has been included for Unit 005 to satisfy the reporting requirements of the NSPS Subpart Dc (Condition numbers refer to the Title V permit):

Condition 38:	The condition establishes the requirements for the submittal of the notification of the date of construction or reconstruction and actual startup of the boiler (Ref. 005), as provided by 40 CFR § 60.7.

The following reporting requirement has been included for the Kewanee package boiler (Ref. 001) to satisfy the reporting requirements of the MACT Subpart JJJJJJ (Condition numbers refer to the Title V permit):

Condition 40:	The permittee shall furnish all applicable written notifications and reports as according to 40 CFR 63.11225 as applicable to the Kewanee package boiler (Ref. 001). This includes Notification of Compliance Status and a Biennial Compliance Status Report.

EMISSION UNIT APPLICABLE REQUIREMENTS

Reciprocating Internal Combustion Engine: 007

The reciprocating internal combustion engine (RICE) (Ref. 007) is a diesel fire pump that was constructed between 1983 and 1985 (an exact date of construction was not available), and has a maximum rated capacity of 150 HP with a displacement of less than 10 liters per cycle. The unit (Ref. 007) is subject to the MACT requirements of 40 CFR 63 Subpart ZZZZ. Since the compliance date for existing sources has passed (May 3, 2013), and the facility was considered a major source of HAPs until shutdown of the coal boilers, the unit is considered an existing emission unit at a major source of HAPs under the MACT "once-in, always-in" rule. The unit is considered an existing emergency-use RICE at a major source of HAPs.

Due to the construction date of the unit (Ref. 007), the New Source Performance Standards, 40 CFR 60 Subpart IIII are not applicable; Subpart IIII standards apply to unit constructed after June 2006.

Limitations

In accordance with the MACT, 40 CFR 63 Subpart ZZZZ, the following conditions are applicable to the unit (condition numbers refer to the Title V permit):

Condition 41:	The RICE (Ref. 007) must be operated in accordance with MACT, Subpart ZZZZ, except where the Title V permit is more restrictive.
Condition 42:	The condition establishes the maintenance requirements for the RICE.
Condition 43:	During periods of startup the permittee must minimize the time spent at idle for the emergency generator (Ref. 007) and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
Condition 44:	The condition establishes the operational limitations for emergency RICE. The condition establishes that emergency generators may be operated for the purpose of maintenance check and readiness testing.

Monitoring and Recordkeeping

The following are monitoring and recordkeeping requirements established to determine compliance with the MACT limitations.

Condition 45:	The permittee must install a non-resettable hour meter prior to start up in accordance with 40 CFR 63.6625. The hour meter shall be provided with adequate access for inspection.
Condition 46:	The permittee must operate and maintain the stationary RICE (Ref. 007) and after-treatment control device (if any) according to the manufacturer's emission related written instructions or develop a

maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

Condition 47: The permittee must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to the stationary RICE (Ref. 007), at all times.

Condition 48: The condition establishes the recordkeeping requirements for the stationary RICE (Ref. 007), necessary to demonstrate compliance with the emission limitations and operating parameters established in the permit.

The requirement for installation of non-resettable hour meters for the stationary RICE, provided in Condition 45, establishes the means of determining compliance with the hour limitations specified in Conditions 42, 43, and 44. The facility is required to keep records of the hours of operation of the stationary RICE to ensure the limitations of Condition 44 are met. The facility is required under Condition 48 to maintain records of all maintenance conducted on the stationary RICE (Ref. 007) as well as the hours of operation of the unit. The requirement to maintain records of the maintenance performed provides a means of determining continuing compliance with the maintenance requirements in Condition 42. The requirement to maintain records of the hours of operation, and type of use, of the unit establishes a means of demonstrating compliance with the usage limitations established in Conditions 43 and 44.

Condition 47 establishes operating and maintenance requirements for the stationary RICE (Ref. 007). Condition 46 requires the operation and maintenance according the manufacturer's written instructions, or the development of a maintenance plan for the stationary RICE (Ref. 007). The required maintenance and operating requirements of Conditions 46 and 47 provide a means of assuring compliance with the maintenance and operating requirements for the generator.

No additional monitoring or recordkeeping requirements are needed other than MACT requirements.

Testing

Condition 49 establishes that the Department and EPA have authority to require testing not included in this permit if necessary to determine compliance with an emission limit or standard.

Reporting

Condition 50 of the Title V permit requires the permittee to report any failure to perform the management practices in Condition 42 for the stationary RICE (Ref. 007), on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

Compliance Assurance Monitoring

The stationary RICE is subject only to emission limitations or standards proposed after November 15, 1990, pursuant to section 111 or 112 of the Clean Air Act, and is therefore exempt from CAM under 40 CFR 64.2(b)(1)(i). CAM is not applicable to the stationary RICE.

GENERAL CONDITIONS

The permit contains general conditions required by 40 CFR Part 72 and 9 VAC 5-80-490, that apply to all acid rain operating permit sources. These include requirements for submitting semi-annual monitoring reports and an annual compliance certification report. The permit also requires notification of deviations from permit requirements or any excess emissions, including those caused by upsets, within one business day.

TITLE IV (PHASE II ACID RAIN) PERMIT ALLOWANCES AND REQUIREMENTS

In accordance with the Air Pollution Control Law of Virginia §10.1-1308 and §10.1-1322, the Environmental Protection Agency (EPA) Final Full Approval of the Operating Permits Program (Titles IV and V) published in the Federal Register December 4, 2001, Volume 66, Number 233, Rules and Regulations, Pages 62961-62967 and effective November 30, 2001, and Title 40, the Code of Federal Regulations §§72.1 through 76.16, the Commonwealth of Virginia Department of Environmental Quality issues Phase II Acid Rain permits pursuant to 9 VAC 5 Chapter 80, Article 3 of the Virginia Regulations for the Control and Abatement of Air Pollution (Article 3 Federal Operating Permit (FOP)).

The Phase II permit was incorporated into the permit including the SO_2 allowance allocations and the NO_x requirements. The application for renewal of Article 3 FOP was received June 28, 2012. Upon renewal, the Article 3 FOP will have an expiration date of December 31, 2018.

The following applicable limitations are state and federal requirements from the Phase II acid rain permit effective January 1, 2014, which will be incorporated into the Title IV federal operating permit.

SO_2 allowance allocations are as follows:

Unit 003	1768 tons	for years 2014 through 2018
Unit 004	5170 tons	for years 2014 through 2018

VEPCO submitted a Phase II Acid Rain Permit renewal application dated June 21, 2012 and received June 28, 2012. Attached to the application was the Phase II NO_x Averaging Plan which included year 2014 through 2018 to coincide with the Acid Rain Permit.

Under the NO_x compliance plan, the annual average NO_x emission rate for each year for Units 003 and 004 are determined in accordance with 40 CFR Part 75; emissions shall not exceed the applicable limitation under 40 CFR 76.7(a)(2), of 0.46 lb/MMBtu of heat input for each unit (dry bottom wall-fired boilers not applying cell burner technology).

A copy of the Title IV Acid Rain Permit, Phase II NO_x Compliance Plan, and Phase II NO_x Averaging Plan applications are provided as Attachment A to the Permit, and Attachment D to the Statement of Basis.

CLEAN AIR INTERSTATE RULE (CAIR) PERMIT

VEPCO submitted a Clean Air Interstate Rule (CAIR) Permit renewal application dated June 4, 2012 and received June 18, 2012. CAIR requirements are included in the renewal permit by reference. Upon renewal, the CAIR permit will have an expiration date of December 31, 2018. A copy of the CAIR Permit application is provided as Attachment B to the Permit, and Attachment D to the Statement of Basis.

STATE ONLY APPLICABLE REQUIREMENTS

None were identified by the applicant.

FUTURE APPLICABLE REQUIREMENTS

None were identified by the applicant.

INAPPLICABLE REQUIREMENTS

The provisions of 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting require owners and operators of general stationary fuel combustion sources that emit 25,000 metric tons CO_{2e} or more per year in combined emissions from such units, to report greenhouse gas (GHG) emissions, annually. The definition of "applicable requirement" in 40 CFR 70.2 and 71.2 does not include requirements such as those included in Part 98, promulgated under Clean Air Act (CAA) section 114(a)(1) and 208. Therefore, the requirements of 40 CFR Part 98 are not applicable under the Title V permitting program.

As a result of several EPA actions regarding GHG under the CAA, emissions of GHG must be addressed for a Title V permit renewed after January 1, 2011. The current state minor NSR and PSD permits for the Bremo Power Station contains no GHG-specific applicable requirements and there have been no modifications at the facility requiring a PSD permit. Therefore, there are no applicable requirements for the facility specific to GHG.

Currently inapplicable requirements identified by the applicant include the following requirements:

40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators, 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, and *40 CFR 60, Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, have been specifically identified as being not applicable to units 003 and 004 as construction of the boilers took place prior to the applicability dates of these standards of performance (August 17, 1971, September 18, 1978, and June 19, 1984, respectively.)

40 CFR 60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 has been identified as being not applicable to units IS-1, IS-3, IS-4, and IS-15 due to the low vapor pressure from each petroleum storage tank.

40 CFR 60 Subpart Y, Standards of Performance for Coal Preparation and Processing Plants is no longer applicable to the facility; the facility no longer handles or combusts coal.

40 CFR 60 Subparts GG, Standards of Performance for Stationary Gas Turbines, and *40 CFR 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines* have been identified as being not applicable to emission unit 002 since the turbine was constructed prior to the first applicability date in NSPS Subpart GG and KKKK. Additionally, 40 CFR 60, Subpart GG was identified as not being applicable to Unit 002 because the unit is less than 10 million BTU/hr heat input

40 CFR 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines has been identified as being not applicable to emission unit 002 in accordance with 40 CFR 63.6090(b)(4); the unit is considered an existing stationary combustion turbine.

40 CFR 63 Subpart UUUUU National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units has been identified as being not applicable to units 003 and 004; the boilers burn only natural gas and are therefore not subject to Subpart UUUUU.

40 CFR 63, Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources has been identified as being not applicable to units 003, 004, 005, and 006. Each unit is natural gas fired; in accordance with 40 CFR 63.11195(e), gas-fired boilers are not subject to the requirements of Subpart JJJJJJ. Subpart JJJJJJ is not applicable to Unit 002 since Unit 002 is a combustion turbine and not a boiler. Subpart JJJJJJ is not applicable to Unit 006 because Unit 006 is a fuel gas heater and not a boiler; the unit (006) does not meet the regulatory definition of a boiler since the unit does not use controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water.

40 CFR 64, Compliance Assurance Monitoring has been identified as being not applicable to units 003 and 004. The units do not meet the general applicability in §64.2(a) since low-NO_x burners and over-fire air are not considered "control devices;" in addition, these units have CEMS for NO_x and CO.

40 CFR 64, Compliance Assurance Monitoring has been identified as being not applicable to units 001, 002, or 005 since each unit does not use a control device to meet the emission standards.

The facility did not identify any additional inapplicable requirements in their application.

In addition to the inapplicable requirements identified by the facility, the following requirements have been identified as inapplicable:

40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units was identified as not being applicable for Units 001 and 006 as each unit is less than 10 million BTU/hr heat input.

40 CFR 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines is not an applicable requirement for the emergency fire pump (007) at the facility. The 150 HP fire pump was constructed and manufactured between 1983 and 1985, before the applicability date of Subpart IIII, and is therefore not subject to NSPS Subpart IIII.

40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Major Sources has been identified as being not applicable to the facility. The facility is an area source of HAPs; therefore the Boiler MACT for Major Sources is not applicable.

COMPLIANCE PLAN

No compliance plan was included in the application or in the permit.

INSIGNIFICANT EMISSION UNITS

The insignificant emission units are presumed to be in compliance with all requirements of the Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping or reporting shall be required for these emission units in accordance with 9 VAC 5-80-490.

Insignificant emission units include the following:

Emission Unit No.	Emission Unit Description	Citation	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity (9 VAC 5-80-720 C)
IS-1	Lube Oil Systems/Waste Oil Systems/Hydraulic Oil Systems	9 VAC 5-80-720B	VOC	--
IS-3	275 Gallon Gasoline Dispensing Station & Tank	9 VAC 5-80-720B	VOC	--
IS-4	500 Gallon Kerosene Tank	9 VAC 5-80-720B	VOC	--
IS-8	Gravel Roads	9 VAC 5-80-720B	PM-10	--
IS-9	Sand Blaster	9 VAC 5-80-720B	PM-10	--
IS-10	Sewage Treatment	9 VAC 5-80-720B	VOC	--
IS-12	Ash Storage Ponds	9 VAC 5-80-720B	PM-10	--
IS-14	Lime Slurry Tank	9 VAC 5-80-720B	PM-10	--
IS-15	275 Gallon Fire Pump Diesel Tank	9 VAC-5-80-720B	VOC	--
006	Natural gas-fired pipeline heater	9 VAC 5-80-720C	--	4/277 MMBtu/hr

[1]The citation criteria for insignificant activities are as follows:

9 VAC 5-80-720 A - Listed Insignificant Activity, Not Included in Permit Application
9 VAC 5-80-720 B - Insignificant due to emission levels
9 VAC 5-80-720 C - Insignificant due to size or production rate

CONFIDENTIAL INFORMATION

The permittee did not submit a request for confidentiality. All portions of the permit application are suitable for public review.

PUBLIC PARTICIPATION

A public notice regarding the draft permit was placed in the Daily Progress, in Charlottesville, Virginia, on November 8, 2013. EPA was sent a copy of the draft permit and notified of the public notice on November 7, 2013. All persons on the Title V mailing list were sent a copy of the public notice by either electronic mail or in letters on November 7, 2013. There are no affected states; there are no other states within 50 miles of the facility. The 30-day public comment period was from November 8, 2013 through December 9, 2013. No public comments were received.

The EPA reviewed the permit concurrently with the public comment period; the EPA comment period ended on December 26, 2013. No comments were received.

ATTACHMENTS

Attachment A - 2012 Annual Emissions Update

Attachment B - Minor NSR Permit dated May 24, 2013, and Associated Engineering Analysis

Attachment C - Emission Calculations: Units 001 and 002

Attachment D - Title IV Acid Rain Permit Application and the CAIR Renewal Application

Attachment A

2012 Annual Emissions Update
(Reg. No. 40199 – Bremo Title V)

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

Registration No: 40199
Plant Name: Dominion - Bremo Power Station

FIPS County Code: 065
Plant ID: 00901

Year of Emissions: 2012
Last Annual Update: 2012

GENERAL INFORMATION

Facility Name: Dominion - Bremo Power Station
Location Address: 1038 Bremo Road
Bremo Bluff VA 23022
Mailing Address: 5000 Dominion Blvd
Glen Allen VA 23060
Annual Update Contact: Taylor, Cathy
Phone Number: (804) 273 - 2929
Principal Product: electricity
Comments:

UTM Zone: 17
UTM Vertical (KM): 4176.8
UTM Horizontal (KM): 739.1
Latitude: 37 ° 42 ' 19 "
Longitude: -78 ° 17 ' 22 "
Property Area (Acres): 281.5
No. of Employees: 78
Primary SIC Code: 4911

Facility Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
PM 10	163.9482458427		
SO2	2950.6429620250		
VOC	4.7364032611		
PB	0.0268204353		
HCL	93.9810000000		
PM 2.5	9.9958242100		
NO2	856.5061564000		
PM	163.9482458427		
CO	40.0923736865		
NH3	0.0535773875		
HF	11.7476250000		

STACK INFORMATION:

Number: 1
Description: Stack 1 Description

Stack Height(ft): 200
Stack Diameter(ft): 12
Exit Gas Temperature(F): 314
Gas Flow Rate(ACFM): 282000
Exit Gas Velocity(ft/sec): 41.56
Stack Type: V
Plume Height(ft): 0
Permitted Equipment: N

UTM Zone: 17
UTM Vertical(KM): 4176.79
UTM Horizontal(KM): 739.09
GEP Stack Height: 0
GEP Building Height: 0
GEP Building Length: 0
GEP Bulding Width: 0
Rough Terrain: N
Elevation (ft above MSL): 220

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units

CO	8.2359250000
HCL	18.9648000000
HF	2.3706000000
NH3	0.0089292600
NO2	226.3000000000
PB	0.0007554324
PM	30.7933300000
PM 10	30.7933300000
PM 2.5	0.9237700000
SO2	604.4000000000
VOC	0.9615970000

POINT INFORMATION: Number: 1 Description: Point 001 Description

Design Capacity & Units: 906 MILLION BTUS Per HOUR

State Sensitive: N
Permitted Equipment: N
Space Heat (%): 1
Air Program Sub Part

% Throughput: DEC-FEB: 41 MAR-MAY: 10 JUN-AUG: 42 SEP-NOV: 7
Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 4214

Point Emissions	Pollutant	Emissions Value (tpy)	Allowable Value	Units
	CO	8.2359250000		
	HCL	18.9648000000		
	HF	2.3706000000		
	NH3	0.0089292600		
	NO2	226.3000000000		
	PB	0.0007554324		
	PM	30.7933300000	128.5100000000	lbs/hr
	PM 10	30.7933300000		
	PM 2.5	0.9237700000		
	SO2	604.4000000000	2407.6800000000	lbs/hr
	VOC	0.9615970000		

SEGMENT INFORMATION: Number: 1 Description: 3 BABCOCK & WILCOX

Source Classification Code: 10100202
Actual Annual Throughput: 31608
Max. Hourly Operation Rate: 30
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N

SCC Description: Pulverized Coal: Dry Bottom (Bituminous Coal)
SCC Units: Tons Burned
Trace%: 0 Ash%: 11.58 Sulfur%: 1.03
Heat Content (MMBTU): 24.89
Throughput Limit:

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

Pollution Prevention: N

Throughput Unit:

Pollution Prevention Comments:

Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	Supplied factor (auto calc)	0.0000480000		010			0.00075543		
			010 = Electrostatic Precipitator - High Efficiency						
NH3	Federal factor (auto calc)	0.0005650000					0.00892926		
PM 2.5	Supplied factor (auto calc)	0.0500000000					0.79020000		
VOC	Supplied factor (auto calc)	0.0600000000					0.94824000		
HF	Supplied factor (auto calc)	0.1500000000					2.37060000		
CO	Supplied factor (auto calc)	0.5000000000					7.90200000		
HCL	Supplied factor (auto calc)	1.2000000000					18.96480000		
PM	Supplied factor (auto calc)	1.9400000000		010			30.65976000		
			010 = Electrostatic Precipitator - High Efficiency						
PM 10	Supplied factor (auto calc)	1.9400000000		010			30.65976000		
			010 = Electrostatic Precipitator - High Efficiency						
NO2 CEMS Data	Source test (user calc)	0.0000000000					226.30000000		
SO2 CEMS Data	Source test (user calc)	0.0000000000					604.40000000		

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

SEGMENT INFORMATION: Number: 2 Description: 3 BABCOCK & WILCOX

Source Classification Code:	10100501	SCC Description:	Grades 1 and 2 Oil
Actual Annual Throughput:	133.57		
Max. Hourly Operation Rate:	6.471	SCC Units:	1000 Gallons Burned
State Sensitive:	N	Trace%:	0 Ash%: .01 Sulfur%: .5
Permitted Equipment:	N	Heat Content (MMBTU):	137
Insignificant Activity:	N		
Pollution Prevention:	N	Throughput Limit:	
		Throughput Unit:	

Pollution Prevention Comments:

Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	Federal factor (auto calc)	0.0000090000		010		99.8	0.00000000		
			010 = Electrostatic Precipitator - High Efficiency						
NO2	Supplied factor (auto calc)	0.0000000000					0.00000000		
Included in CEMS for Coal									
SO2	Supplied factor (auto calc)	0.0000000000					0.00000000		
Included in CEMS for Coal									
VOC	Federal factor (auto calc)	0.2000000000					0.01335700		
PM	Federal factor (auto calc)	2.0000000000		010			0.13357000		
			010 = Electrostatic Precipitator - High Efficiency						
PM 10	Supplied factor (auto calc)	2.0000000000		010			0.13357000		
			010 = Electrostatic Precipitator - High Efficiency						
PM 2.5	Supplied factor (auto calc)	2.0000000000					0.13357000		
Used PM10 AP42									
CO	Federal factor (auto calc)	5.0000000000					0.33392500		

SEGMENT INFORMATION: Number: 3 Description: 3 B&W BLR USED OIL

Source Classification Code:	10101302	SCC Description:	Waste Oil
Actual Annual Throughput:	0		
		SCC Units:	

1000 Gallons Burned

Max. Hourly Operation Rate: 0
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

Trace%: 0 Ash%: 0 Sulfur%: .5
Heat Content (MMBTU): 0
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PM 10	Supplied factor (auto calc)	0.6400000000					0.00000000		
VOC	Federal factor (auto calc)	1.0000000000					0.00000000		
CO	Federal factor (auto calc)	5.0000000000					0.00000000		
NO2	Supplied factor (auto calc)	19.0000000000					0.00000000		
PM	Supplied factor (auto calc)	64.0000000000					0.00000000		
SO2	Federal factor (auto calc)	147.0000000000	S				0.00000000		

STACK INFORMATION: Number: 2 Description: Stack 2 Description

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

Stack Height(ft):	200
Stack Diameter(ft):	15
Exit Gas Temperature(F):	264
Gas Flow Rate(ACFM):	475000
Exit Gas Velocity(ft/sec):	44.8
Stack Type:	V
Plume Height(ft):	0
Permitted Equipment:	N

UTM Zone:	17
UTM Vertical(KM):	4176.79
UTM Horizontal(KM):	739.09
GEP Stack Height:	0
GEP Building Height:	0
GEP Building Length:	0
GEP Bulding Width:	0
Rough Terrain:	N
Elevation (ft above MSL):	220

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
CO	31.7980500000		
HCL	75.0162000000		
HF	9.3770250000		
NH3	0.0353201275		
NO2	629.9000000000		
PB	0.0260650029		
PM	131.4065200000		
PM 10	131.4065200000		
PM 2.5	7.3778030000		
SO2	2345.4000000000		
VOC	3.7724620000		

POINT INFORMATION: Number: 2 Description: Point 002 Description

Design Capacity & Units: 1698 MILLION BTUS Per HOUR

% Throughput: DEC-FEB: 23 MAR-MAY: 13 JUN-AUG: 48 SEP-NOV: 16

Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 6268

State Sensitive:	N
Permitted Equipment:	N
Space Heat (%):	1
Air Program	Sub Part

Point Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
CO	31.7980500000		
HCL	75.0162000000		
HF	9.3770250000		
NH3	0.0353201275		
NO2	629.9000000000		
PB	0.0260650029		
PM	131.4065200000	239.9500000000	lbs/hr
PM 10	131.4065200000		
PM 2.5	7.3778030000		
SO2	2345.4000000000	4485.3600000000	lbs/hr
VOC	3.7724620000		

SEGMENT INFORMATION: Number: 1 Description: 4 BABCOCK & WILCOX

Source Classification Code: 10100202
Actual Annual Throughput: 125027
Max. Hourly Operation Rate: 55.8
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Pulverized Coal: Dry Bottom (Bituminous Coal)
SCC Units: Tons Burned
Trace%: 0 Ash%: 11.7 Sulfur%: 1.04
Heat Content (MMBTU): 24.86
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	AP-42 factor (user calc)	0.0000000000		010		84.5	0.02606500		
	010 = Electrostatic Precipitator - High Efficiency								
PM 10	Source test (user calc)	0.0000000000		010		99.2	131.19000000		
	010 = Electrostatic Precipitator - High Efficiency								
PM	Source test (user calc)	0.0000000000		010		99.7	131.19000000		
	010 = Electrostatic Precipitator - High Efficiency								
NH3	Federal factor (auto calc)	0.0005650000					0.03532012		
VOC	Supplied factor (auto calc)	0.0600000000					3.75081000		
HF	Supplied factor (auto calc)	0.1500000000					9.37702500		
CO	Supplied factor (auto calc)	0.5000000000					31.25675000		
HCL	Supplied factor (auto calc)	1.2000000000					75.01620000		
PM 2.5	Source test (user calc)	0.0000000000		010			7.21000000		
	010 = Electrostatic Precipitator - High Efficiency								
NO2 CEMS Data	Source test (user calc)	0.0000000000					629.90000000		
SO2 CEMS Data	Source test (user calc)	0.0000000000					2345.40000000		

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

SEGMENT INFORMATION: Number: 2 Description: 4 BABCOCK & WILCOX

Source Classification Code: 10100501
Actual Annual Throughput: 216.52
Max. Hourly Operation Rate: 12.129
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Grades 1 and 2 Oil
SCC Units: 1000 Gallons Burned
Trace%: 0 Ash%: .01 Sulfur%: .5
Heat Content (MMBTU): 137
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PB	Federal factor (auto calc)	0.0000090000		010		99.7	0.00000000		
	010 = Electrostatic Precipitator - High Efficiency								
VOC	Federal factor (auto calc)	0.2000000000					0.02165200		
PM 2.5	Federal factor (auto calc)	1.5500000000					0.16780300		
PM	Federal factor (auto calc)	2.0000000000		010			0.21652000		
	010 = Electrostatic Precipitator - High Efficiency								
PM 10	Supplied factor (auto calc)	2.0000000000		010			0.21652000		
	010 = Electrostatic Precipitator - High Efficiency								
CO	Federal factor (auto calc)	5.0000000000					0.54130000		
NO2	Source test (user calc)	0.0000000000					0.00000000		
Included in CEMS for Coal									
SO2	Source test (user calc)	0.0000000000					0.00000000		
Included in CEMS for Coal									

SEGMENT INFORMATION: Number: 3 Description: 4 B&W BLR - USED OIL

Source Classification Code: 10101302 SCC Description: Waste Oil
Actual Annual Throughput:

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

	0	SCC Units:	1000 Gallons Burned
Max. Hourly Operation Rate:	0	Trace%:	0 Ash%: 0 Sulfur%: .5
State Sensitive:	N	Heat Content (MMBTU):	0
Permitted Equipment:	N		
Insignificant Activity:	N	Throughput Limit:	
Pollution Prevention:	N	Throughput Unit:	

Pollution Prevention Comments:

Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PM 10	Supplied factor (auto calc)	0.6400000000					0.00000000		
VOC	Federal factor (auto calc)	1.0000000000					0.00000000		
CO	Federal factor (auto calc)	5.0000000000					0.00000000		
NO2	Supplied factor (auto calc)	19.0000000000					0.00000000		
PM	Supplied factor (auto calc)	64.0000000000					0.00000000		
SO2	Federal factor (auto calc)	147.0000000000	S				0.00000000		

STACK INFORMATION: Number: 3 Description: Stack 3 Description

Stack Height(ft):	0
Stack Diameter(ft):	0
Exit Gas Temperature(F):	0
Gas Flow Rate(ACFM):	0
Exit Gas Velocity(ft/sec):	0
Stack Type:	F
Plume Height(ft):	30
Permitted Equipment:	N

UTM Zone:	17
UTM Vertical(KM):	4176.79
UTM Horizontal(KM):	739.09
GEP Stack Height:	0
GEP Building Height:	0
GEP Building Length:	0
GEP Bulding Width:	0
Rough Terrain:	N
Elevation (ft above MSL):	220

Stack Emissions	Pollutant	Emissions Value (tpy)	Allowable Value	Units
	PM	1.7095589827	4.8000000000	tons/yr
	PM 10	1.7095589827	2.1000000000	tons/yr
	PM 2.5	1.6709312100		

POINT INFORMATION: Number: 3 Description: Point 003 Description

Design Capacity & Units: 0 MILLION BTUS Per HOUR

% Throughput: DEC-FEB: 20 MAR-MAY: 14 JUN-AUG: 50 SEP-NOV: 16

Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

State Sensitive:	N
Permitted Equipment:	N
Space Heat (%):	0
Air Program	Sub Part

Point Emissions	Pollutant	Emissions Value (tpy)	Allowable Value	Units
	PM	1.7095589827	1.6000000000	lbs/hr
			4.8000000000	tons/yr
	PM 10	1.7095589827	0.7000000000	lbs/hr
			2.1000000000	tons/yr
	PM 2.5	1.6709312100		

SEGMENT INFORMATION: Number: 1 Description: COAL UNLOADING

Source Classification Code:	30501008	SCC Description:	Unloading
Actual Annual Throughput:	123516		
Max. Hourly Operation Rate:	340	SCC Units:	Tons Coal Shipped
State Sensitive:	N	Trace%:	0 Ash%: 0 Sulfur%: 0
Permitted Equipment:	N	Heat Content (MMBTU):	0
Insignificant Activity:	N	Throughput Limit:	3212000
Pollution Prevention:	N	Throughput Unit:	Tons Coal

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PM 2.5	Supplied factor (auto calc)	0.0000900000		054		50	0.00277911		
			054 = Process Enclosed						
PM	Supplied factor (auto calc)	0.0006440000		054		50	0.01988607		
			054 = Process Enclosed						
PM 10	Supplied factor (auto calc)	0.0006440000		054		50	0.01988607		
			054 = Process Enclosed						

SEGMENT INFORMATION: Number: 2 Description: RAW COAL STORAGE(2)

Source Classification Code: 30501009
Actual Annual Throughput: 156634
Max. Hourly Operation Rate: 340
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: Raw Coal Storage
SCC Units: Tons Coal Shipped
Trace%: 0 Ash%: 0 Sulfur%: 0
Heat Content (MMBTU): 0
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PM	Supplied factor (auto calc)	0.0211000000					1.65248870		
PM 10	Supplied factor (auto calc)	0.0211000000					1.65248870		
PM 2.5	Supplied factor (auto calc)	0.0211000000					1.65248870		

SEGMENT INFORMATION: Number: 3 Description: 1 COAL CRUSHER

Source Classification Code:	30501010	SCC Description:	Crushing
Actual Annual Throughput:	156634		
Max. Hourly Operation Rate:	340	SCC Units:	Tons Coal Shipped
State Sensitive:	N	Trace%:	0 Ash%: 0 Sulfur%: 0
Permitted Equipment:	N	Heat Content (MMBTU):	0
Insignificant Activity:	N	Throughput Limit:	
Pollution Prevention:	N	Throughput Unit:	

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PM	Supplied factor (auto calc)	0.0200000000		054	018	99	0.01566340		
			054 = Process Enclosed		018 = Fabric Filter - Low Temperature i.e. T<180F				
PM 10	Supplied factor (auto calc)	0.0200000000		054	018	99	0.01566340		
			054 = Process Enclosed		018 = Fabric Filter - Low Temperature i.e. T<180F				
PM 2.5	Supplied factor (auto calc)	0.0200000000		054		99	0.01566340		
			054 = Process Enclosed						

SEGMENT INFORMATION: Number: 4 Description: 3 COAL CONV/HNDL/SCREEN

Source Classification Code:	30501011	SCC Description:	Coal Transfer
Actual Annual Throughput:	156634		
Max. Hourly Operation Rate:	340	SCC Units:	Tons Coal Shipped
State Sensitive:	N	Trace%:	0 Ash%: 0 Sulfur%: 0
Permitted Equipment:	N	Heat Content (MMBTU):	0
Insignificant Activity:	N	Throughput Limit:	
Pollution Prevention:	N	Throughput Unit:	

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
PM	Supplied factor (auto calc)	0.0036300000		054		92.43	0.02152080		
			054 = Process Enclosed						
PM 10	Supplied factor (auto calc)	0.0036300000		054		92.43	0.02152080		
			054 = Process Enclosed						

STACK INFORMATION: Number: 4 Description: Stack 4 Description

Stack Height(ft):	40	UTM Zone:	17
Stack Diameter(ft):	1.33	UTM Vertical(KM):	4176.8
Exit Gas Temperature(F):	100	UTM Horizontal(KM):	739.1
Gas Flow Rate(ACFM):	1	GEP Stack Height:	0
Exit Gas Velocity(ft/sec):	.01	GEP Building Height:	0
Stack Type:	V	GEP Building Length:	0
Plume Height(ft):	0	GEP Bulding Width:	0
Permitted Equipment:	N	Rough Terrain:	N
		Elevation (ft above MSL):	220

Stack Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
CO	0.0583000000		
NH3	0.0093280000		
NO2	0.2798400000		
PM	0.0384780000		
PM 10	0.0384780000		
PM 2.5	0.0233200000		
SO2	0.8278600000		
VOC	0.0023320000		

POINT INFORMATION: Number: 4 Description: Point 004 Description

Design Capacity & Units: 0
Per

% Throughput: DEC-FEB: 100 MAR-MAY: 0 JUN-AUG: 0 SEP-NOV: 0

State Sensitive: N
Permitted Equipment: N
Space Heat (%): 0
Air Program Sub Part

Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

Point Emissions

Pollutant	Emissions Value (tpy)	Allowable Value	Units
CO	0.0583000000		
NH3	0.0093280000		
NO2	0.2798400000		
PM	0.0384780000	5.2200000000	lbs/hr
PM 10	0.0384780000		
PM 2.5	0.0233200000		
SO2	0.8278600000	22.9500000000	lbs/hr
VOC	0.0023320000		

SEGMENT INFORMATION: Number: 1 Description: PACKAGE BLR- #2 OIL

Source Classification Code: 10200501
Actual Annual Throughput: 23.32
Max. Hourly Operation Rate: 0
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

SCC Description: >100 MMBtu/hr
SCC Units: 1000 Gallons Burned
Trace%: 0 Ash%: 0 Sulfur%: .5
Heat Content (MMBTU): 0
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
VOC	Supplied factor (auto calc)	0.2000000000					0.00233200		
NH3	Supplied factor (auto calc)	0.8000000000					0.00932800		
PM 2.5	Supplied factor (auto calc)	2.0000000000					0.02332000		
PM	Supplied factor (auto calc)	3.3000000000					0.03847800		
PM 10	Supplied factor (auto calc)	3.3000000000					0.03847800		

CO	Federal factor (auto calc)	5.0000000000	0.05830000
NO2	Federal factor (auto calc)	24.0000000000	0.27984000
SO2	Supplied factor (auto calc)	71.0000000000	0.82786000

SEGMENT INFORMATION: Number: 2 Description: PACKAGE BLR- PROPANE

Source Classification Code:	10201002	SCC Description:	Propane
Actual Annual Throughput:	0		
Max. Hourly Operation Rate:	0	SCC Units:	1000 Gallons Burned
State Sensitive:	N	Trace%:	0 Ash%: 0 Sulfur%: 0
Permitted Equipment:	N	Heat Content (MMBTU):	0
Insignificant Activity:	N	Throughput Limit:	
Pollution Prevention:	N	Throughput Unit:	

Pollution Prevention Comments:

Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
SO2	Supplied factor (auto calc)	0.0220000000					0.00000000		
PM 10	Supplied factor (auto calc)	0.1650000000					0.00000000		
VOC	Supplied factor (auto calc)	0.2130000000					0.00000000		
PM	Federal factor (auto calc)	0.7000000000					0.00000000		
NO2	Supplied factor (auto calc)	3.6800000000					0.00000000		
CO	Federal factor (auto calc)	7.5000000000					0.00000000		

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

STACK INFORMATION: Number: 5 Description: Stack 5 Description

Stack Height(ft):	15	UTM Zone:	17
Stack Diameter(ft):	1.33	UTM Vertical(KM):	4176.8
Exit Gas Temperature(F):	60	UTM Horizontal(KM):	739.1
Gas Flow Rate(ACFM):	1	GEP Stack Height:	0
Exit Gas Velocity(ft/sec):	.01	GEP Building Height:	0
Stack Type:	V	GEP Building Length:	0
Plume Height(ft):	0	GEP Bulding Width:	0
Permitted Equipment:	N	Rough Terrain:	N
		Elevation (ft above MSL):	220

Stack Emissions	Pollutant	Emissions Value (tpy)	Allowable Value	Units
	CO	0.0000986865		
	NO2	0.0263164000		
	PM	0.0003588600		
	PM 10	0.0003588600		
	SO2	0.0151020250		
	VOC	0.0000122611		

POINT INFORMATION: Number: 5 Description: Point 005 Description

Design Capacity & Units: 0
Per

% Throughput: DEC-FEB: 20 MAR-MAY: 31 JUN-AUG: 27 SEP-NOV: 22
Operating Schedule: Hours/Day: 24 Days/Week: 7 Hours/Year: 8760

State Sensitive: N
Permitted Equipment: N
Space Heat (%): 0
Air Program Sub Part

Point Emissions	Pollutant	Emissions Value (tpy)	Allowable Value	Units
	CO	0.0000986865		
	NO2	0.0263164000		
	PM	0.0003588600	2.0000000000	lbs/hr
	PM 10	0.0003588600		
	SO2	0.0151020250	13.8300000000	lbs/hr
	VOC	0.0000122611		

SEGMENT INFORMATION: Number: 1 Description: SOLAR CT_- KEROSENE

Source Classification Code:	20100101	SCC Description:	Turbine
Actual Annual Throughput:	59.81		
Max. Hourly Operation Rate:	0	SCC Units:	Million BTUs Fuel Input
State Sensitive:	N	Trace%:	0

Ash%: 0 Sulfur%: .5

Commonwealth of Virginia
Department of Environmental Quality
Consolidated Plant Emissions Report

Permitted Equipment: N
Insignificant Activity: N
Pollution Prevention: N

Heat Content (MMBTU): 0
Throughput Limit:
Throughput Unit:

Pollution Prevention Comments:
Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
VOC	Federal factor (auto calc)	0.0004100000					0.00001226		
CO	Federal factor (auto calc)	0.0033000000					0.00009868		
PM	Federal factor (auto calc)	0.0120000000					0.00035886		
PM 10	Federal factor (auto calc)	0.0120000000					0.00035886		
NO2	Federal factor (auto calc)	0.8800000000					0.02631640		
SO2	Federal factor (auto calc)	1.0100000000	S				0.01510202		

SEGMENT INFORMATION: Number: 2 Description: SOLAR CT- #2 OIL

Source Classification Code: 20100101
Actual Annual Throughput: 0
Max. Hourly Operation Rate: 0
State Sensitive: N
Permitted Equipment: N
Insignificant Activity: N

SCC Description: Turbine
SCC Units: Million BTUs Fuel Input
Trace%: 0 Ash%: 0 Sulfur%: .5
Heat Content (MMBTU): 0
Throughput Limit:

Pollution Prevention: N

Throughput Unit:

Pollution Prevention Comments:

Segment Comments:

Segment Emissions

Pollutant	Method	Factor	A/S/T	Primary Control	Secondary Control	Overall Efficiency %	Emissions Value (tpy)	Allowable Value	Units
CO	Federal factor (auto calc)	0.0033000000					0.00000000		
PM 10	Supplied factor (auto calc)	0.0120000000					0.00000000		
SO2	Supplied factor (auto calc)	0.5100000000					0.00000000		
NO2	Supplied factor (auto calc)	0.8800000000					0.00000000		
VOC	Supplied factor (auto calc)	2.2950000000					0.00000000		
PM	Supplied factor (auto calc)	8.5400000000					0.00000000		

Bremo Power Station

Emission Unit	003	
Manufacturer	Babcock and Wilcox	
Boiler Type	Pulverized Coal	
Maximum Rated Heat Input C	912	MMBtu/hr
Fuel Type	Coal	
Higher Heating Value	12155	Btu/lb
Sulfur Content	0.95	%
Ash Content	12.18	%
Tons Coal Burned	31068	tons/yr

Emissions Calculations Using AP-42 Emission Factors

Actual Emissions 2012

Pollutant	Emission Factor		Emission Factor Source	Control Efficiency*	Actual Heat Input (10^{12} Btu/yr or tons/yr)	Annual Emissions (tons/yr)
Lead	507.00	lb/10^{12} Btu	AP-42 Table 1.1-17	84.5	0.08	0.02
Arsenic	684.00	lb/10^{12} Btu	AP-42 Table 1.1-17	87.5	0.08	0.03
Beryllium	81.00	lb/10^{12} Btu	AP-42 Table 1.1-17	91.9	0.08	0.00
Cadmium	44.40	lb/10^{12} Btu	AP-42 Table 1.1-17	74.6	0.08	0.00
Chromium	1410.00	lb/10^{12} Btu	AP-42 Table 1.1-17	71.5	0.08	0.05
Manganese	1604.00	lb/10^{12} Btu	AP-42 Table 1.1-17	78.1	0.08	0.06
Mercury	16.00	lb/10^{12} Btu	AP-42 Table 1.1-17	NA	0.08	0.00
Nickel	1160.00	lb/10^{12} Btu	AP-42 Table 1.1-17	79.1	0.08	0.04
POM	2.08	lb/10^{12} Btu	AP-42 Table 1.1-17	NA	0.08	0.00
HCL	1.2	lb/ton	AP-42 Table 1.1-15	NA	31068.00	18.64
HF	0.15	lb/ton	AP-42 Table 1.1-15	NA	31068.00	2.33

* Toxic Control Efficiencies for ESPs from EPA Document EPA 450/2-89-001

Bremo Power Station

Emission Unit	004	
Manufacturer	Babcock and Wilcox	
Boiler Type	Pulverized Coal	
Maximum Rated Heat Input C	1699	MMBtu/hr
Fuel Type	Coal	
Higher Heating Value	12170	Btu/lb
Sulfur Content	0.97	%
Ash Content	12.12	%
Tons Coal Burned	125027	tons/yr

Emissions Calculations Using AP-42 Emission Factors

Actual Emissions 2012

Pollutant	Emission Factor		Emission Factor Source	Control Efficiency*	Actual Heat Input (10^{12} Btu/yr or tons/yr)	Annual Emissions (tons/yr)
Lead	507.00	lb/10^{12} Btu	AP-42 Table 1.1-17	84.5	0.30	0.08
Arsenic	684.00	lb/10^{12} Btu	AP-42 Table 1.1-17	87.5	0.30	0.10
Beryllium	81.00	lb/10^{12} Btu	AP-42 Table 1.1-17	91.9	0.30	0.01
Cadmium	44.40	lb/10^{12} Btu	AP-42 Table 1.1-17	74.6	0.30	0.01
Chromium	1410.00	lb/10^{12} Btu	AP-42 Table 1.1-17	71.5	0.30	0.21
Manganese	1604.00	lb/10^{12} Btu	AP-42 Table 1.1-17	78.1	0.30	0.24
Mercury	16.00	lb/10^{12} Btu	AP-42 Table 1.1-17	NA	0.30	0.00
Nickel	1160.00	lb/10^{12} Btu	AP-42 Table 1.1-17	79.1	0.30	0.18
POM	2.08	lb/10^{12} Btu	AP-42 Table 1.1-17	NA	0.30	0.00
HCL	1.2	lb/ton	AP-42 Table 1.1-15	NA	125027.00	75.02
HF	0.15	lb/ton	AP-42 Table 1.1-15	NA	125027.00	9.38

* Toxic Control Efficiencies for ESPs from EPA Document EPA 450/2-89-001

Attachment B

Minor NSR Permit dated May 24, 2013,
and Associated Engineering Analysis
(Reg. No. 40199 – Bremo Title V)

COMMONWEALTH of VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY
VALLEY REGIONAL OFFICE
4411 Early Road, P.O. Box 3000, Harrisonburg, Virginia 22801
(540) 574-7800 Fax (540) 574-7878
www.deq.virginia.gov

Douglas W. Domenech
Secretary of Natural Resources

David K. Paylor
Director

Amy Thatcher Owens
Regional Director

May 24, 2013

Mr. Robert B. McKinley
VP Generation Construction
Virginia Electric & Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Facility: Bremo Power Station
Location: Bremo Bluff
Registration No.: 40199
Plant ID No.: 51-065-0001

Dear Mr. McKinley:

Attached is a permit to modify and operate an electric power generating facility in accordance with the provisions of the Commonwealth of Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. This permit allows modification of Boilers 003 and 004 to change the allowable fuel from coal to natural gas.

The permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and civil penalty. Please read all permit conditions carefully.

The Department of Environmental Quality (DEQ) deemed the application complete on April 22, 2013. This permit approval to modify and operate shall not relieve Virginia Electric & Power Company (Dominion) of the responsibility to comply with all other local, state, and federal permit regulations.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. 9 VAC 5-170-200 provides that you may request direct consideration of the decision by the Board if the Director of the DEQ made the decision. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P.O. Box 1105
Richmond, Virginia 23240-0009

If this permit was delivered to you by mail, three days are added to the period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia, at http://www.courts.state.va.us/courts/scv/rules.html, for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit amendment, please contact Jeremy Funkhouser at 540-574-7820, or through electronic mail at jeremy.funkhouser@deq.virginia.gov.

Sincerely,

B. Keith Fowler
Deputy Regional Director

Attachments: Permit
NSPS, Subpart Dc (submitted electronically)

c: File DEQ – VRO
Compliance/Air Inspector – Barry Brandon

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

STATIONARY SOURCE PERMIT TO MODIFY AND OPERATE

This permit includes designated equipment subject to New Source Performance Standards (NSPS)

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Virginia Electric & Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060
Registration No.: 40199
Plant ID No.: 51-065-0001

is authorized to modify and operate

an electric power generating facility

located at

1038 Bremo Road
Bremo Bluff, Virginia

in accordance with the Conditions of this permit.

Approved on 5/24/13

Deputy Regional Director, Valley Region

Permit consists of 13 pages.
Permit Conditions 1 to 31.
Attachment, Source Testing Report Format, 1 page.

INTRODUCTION

This permit approval is based on the permit applications dated June 15, 2012 and November 19, 2012, including supplemental information dated October 23, 2012, November 27, 2012 and April 4, 2013. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

PROCESS REQUIREMENTS

1. **Equipment List** – Equipment at this facility consists of the following:

Equipment to be Modified			
Reference No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
003	Babcock and Wilcox Natural Gas-fired boiler	920 MMBtu/hr	--
004	Babcock and Wilcox Natural Gas-fired Boiler	1684 MMBtu/hr	--

Exempt from Permitting			
Reference No.	Equipment Description	Rated Capacity	Federal Requirements
005	Natural Gas-fired Auxillary Boiler	25.0 MMBtu/hr	40 CFR 60, Subpart Dc
006	Natural Gas-fired Pipeline Heater	4.277 MMBtu/hr	

Specifications included in the permit under this Condition are for informational purposes only and do not form enforceable terms or conditions of the permit.
(9 VAC 5-80-1180 D 3)

2. **Emission Controls: Nitrogen Oxides** – Oxides of nitrogen (NO_x) emissions from the boilers (Ref. 003 and 004) shall be controlled by low NO_x burners with enhanced overfire air, good combustion practices, operator training and proper emissions unit design, construction and maintenance. The low NO_x burners shall be installed and operated in accordance with manufacturer's specifications.
(9 VAC 5-80-1180)

3. **Emission Controls: Carbon Monoxide and Volatile Organic Compounds** – Carbon monoxide (CO) and volatile organic compound (VOC) emissions from the boilers (Ref. 003 and 004) shall be controlled by enhanced overfire air, good combustion practices, operator training and proper emissions unit design, construction and maintenance.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

4. **Testing/Monitoring Ports** - The electric power generating facility shall be modified so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from cyclonic flow. Sampling ports shall be provided when requested at the appropriate locations and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30 F and 9 VAC 5-80-1180)

<u>OPERATING LIMITATIONS – BOILERS</u>

5. **Fuel (Ref. 003 and 004)** - The approved fuel for the boilers (Ref. 003 and 004) is natural gas. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

6. **Fuel Throughput (Ref. 003 and 004)** – The boilers (Ref. 003 and 004) combined shall consume no more than 6,330 x 10^6 cubic feet of natural gas, per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month

period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

EMISSION LIMITATIONS

7. **Short-term Emission Limits (Ref. 003)** - Emissions from the operation of the boiler (Ref. 003) shall not exceed the limits specified below:

Particulate Matter (PM)	6.81 lb/hr
PM-10	6.81 lb/hr
PM-2.5	6.81 lb/hr
Sulfur Dioxide (SO_2)	0.76 lb/hr
Nitrogen Oxides (as NO_2)	147.20 lb/hr 0.16 lb/MMBtu
Carbon Monoxide (CO)	55.20 lb/hr 0.06 lb/MMBtu
Volatile Organic Compounds (VOC)	3.68 lb/hr 0.004 lb/MMBtu

Unless otherwise specified, NOx and CO limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 10 of this permit. Compliance with these emission limits may be determined as stated in Conditions 13 and 18.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

8. **Short-term Emission Limits (Ref. 004)** - Emissions from the operation of the boiler (Ref. 004) shall not exceed the limits specified below:

Particulate Matter (PM)	12.46 lb/hr
PM-10	12.46 lb/hr
PM-2.5	12.46 lb/hr
Sulfur Dioxide (SO_2)	1.40 lb/hr
Nitrogen Oxides (as NO_2)	252.60 lb/hr 0.15 lb/MMBtu

Carbon Monoxide (CO)	101.04 lb/hr 0.06 lb/MMBtu
Volatile Organic Compounds (VOC)	6.74 lb/hr 0.004 lb/MMBtu

Unless otherwise specified, NOx and CO limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 10 of this permit. Compliance with these emission limits may be determined as stated in Conditions 13 and 18.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

9. **Annual Emission Limits (Ref. 003 and 004)** – Combined emissions from the operation of the boilers (Ref. 003 and 004) shall not exceed the limits specified below:

Particulate Matter (PM)	24.2 tons/yr
PM-10	24.2 tons/yr
PM-2.5	24.2 tons/yr
Sulfur Dioxide (SO_2)	2.7 tons/yr
Nitrogen Oxides (as NO_2)	522.9 tons/yr
Carbon Monoxide (CO)	196.1 tons/yr
Volatile Organic Compounds (VOC)	13.1 tons/yr

Annual emission limits are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 2, 3, 5, and 6.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

10. **Startup and Shutdown** - The NOx and CO short-term emission limits contained in Conditions 7 and 8 apply at all times except during periods of startup and shutdown.

a. Startup and shutdown periods are defined as follows:

i. Startup – A startup begins when the unit begins combusting fuel after a shutdown and ends when the unit is operating above 40% of rated load. Exclusion from the short-term emission limits for startup periods shall not exceed 16 hours per occurrence. Emissions from the operation of the boilers (Ref. 003 and 004) shall not exceed the limits specified below for each startup:

Pollutant	Unit 003	Unit 004
NOx	2,355.2 lbs/startup	4,041.6 lbs/startup
CO	883.2 lbs/startup	1,616.6 lbs/startup

ii. Shutdown – Refers to the period between the time the boiler load drops below 40% of rated load and the fuel supply to the boiler is cut. Exclusion from the short-term emissions limits for shutdown shall not exceed 8 hours per occurrence. Emissions from the operation of the boilers (Ref. 003 and 004) shall not exceed the limits specified below for each shutdown:

Pollutant	Unit 3	Unit 4
NOx	1,177.6 lbs/shutdown	2,020.8 lbs/shutdown
CO	441.0 lbs/shutdown	808.3 lbs/shutdown

b. The permittee shall operate the Continuous Emission Monitoring Systems (CEMS) during periods of startup and shutdown.

c. The permittee shall record the time, date, and duration of each startup and shutdown period.

d. The permittee shall operate the facility so as to minimize the frequency and duration of startup and shutdown events.

(9 VAC 5-80-1180 and 9 VAC 5-50-260)

11. **Emissions Cap (Ref. 003 and 004)** – The annual emissions limit on the boilers (Ref. 003 and 004) in Condition 9 is a compliance cap, imposed for the purpose of limiting the potential to emit carbon monoxide so as to avoid permitting applicability under 9 VAC 5 Chapter 80 Article 8 (9 VAC 5-80-1605 *et seq.*) related to the conversion of the boilers from coal to natural gas. The limit does not provide relief from obtaining a plan approval for any future physical change or change in the method of operation of either boiler or the addition or modification of any steam-consuming process(es) at the facility. The latter is true even if the permittee does not request a change in the compliance cap. Furthermore, by accepting this cap and agreeing to consider the two boilers as one emissions unit for NSR/PSD purposes,

any future applicability determinations must involve both boilers, e.g. should major NSR/PSD be triggered for any one boiler or process change, BACT/LAER is required for both boilers. If the emissions limit is relaxed at some future date, the source obligation requirements of 9 VAC5-80-1605.C and 40 CFR 52.21(r)(4) apply.
(9 VAC 5-80-1605)

12. **Visible Emission Limit** – Visible emissions from each boiler (Ref. 003 and 004) stack shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-80-1180 and 9 VAC 5-50-80)

CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

13. **CEMS** - Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO_x (measured as NO_2) and CO, in lb/MMBtu from each boiler (Ref. 003 and 004). CEMS for NO_x shall meet the design specifications of 40 CFR 75 whereas CEMS for CO shall be installed, evaluated, and operated according to DEQ-approved procedures which are equivalent to the requirements of 40 CFR 60.13 and Appendices B and F for compliance with the emission limits contained in Conditions 7 and 8. NO_x data and CO data shall each be reduced to 1-hour block averages. The relative accuracy test audit (RATA) of the NO_x CEMS shall be performed on a lb/MMBtu basis.
(9 VAC 5-50-40, 9 VAC 5-80-420, and 40 CFR 75)

14. **CEMS Performance Evaluations** - Performance evaluations of the NO_x and CO continuous monitoring systems shall be conducted in accordance with 40 CFR 60, Appendix B, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the DEQ, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30-day notification, prior to the demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the DEQ.
(9 VAC 5-50-40)

15. **CEMS Quality Control Program** - A CEMS quality control program which is equivalent to the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix F or Part 75 shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-40)

16. **Reports for Continuous Monitoring Systems** - The permittee shall furnish written reports to the DEQ of excess emissions from any process monitored by a continuous monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

    b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

    c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

    d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

    (9 VAC 5-50-50)

RECORDS

17. **On Site Records** - The permittee shall maintain records of all emission data and operating parameters necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the DEQ. These records shall include, but are not limited to:

    a. Annual throughput of natural gas for boilers Ref. 003 and 004, calculated monthly as the sum of each consecutive 12-month period.

    b. Emissions calculations sufficient to verify compliance with the annual emission limitations in Condition 9.

    c. Records, of bypass, malfunction, shutdown, or failure of boilers Ref. 003 or 004 or its associated air pollution control equipment as required in Condition 25.

    d. Scheduled and unscheduled maintenance and operator training.

    e. Results of all stack tests and visible emission evaluations.

    f. Continuous monitoring system calibrations and calibration checks, percent operating time, and excess emissions.

g. Written operating procedures, scheduled and unscheduled maintenance and operator training, as required by Condition 29.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-1180 and 9 VAC 5-50-50)

INITIAL COMPLIANCE DETERMINATION

18. **Stack (Performance) Test (Ref. 003 and 004)** – The permittee shall conduct initial performance tests for PM-10, PM-2.5, nitrogen oxides (measured as NO_2), CO, and VOC for each boiler (Ref. 003 and 004). The tests shall be performed on each boiler (Ref. 003 and 004) to determine compliance with the emission limits contained in Conditions 7 and 8. The tests shall be performed within 60 days after achieving the maximum production rate at which the boiler will be operated but in no event later than 180 days after start-up of the permitted boiler. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1200)

19. **Visible Emissions Evaluation** – Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall also be conducted by the permittee on each boiler (Ref. 003 and 004. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six minute average. The observation period may be reduced from 30 sets to 10 sets if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed within 180 days after startup. Should conditions prevent concurrent opacity observations, the DEQ shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the DEQ within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1200)

CONTINUING COMPLIANCE DETERMINATION

20. **Stack Tests** – Upon request by the DEQ, the permittee shall conduct additional stack tests from the boilers (Ref. 003 and 004), to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the DEQ.
(9 VAC 5-80-1200 and 9 VAC 5-50-30 G)

21. **Visible Emissions Evaluation** – Upon request by the DEQ, the permittee shall conduct additional Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9 on each boiler (Ref. 003 and 004) to demonstrate compliance with the visible emission limits contained in the permit. The details of the tests shall be arranged with the DEQ.
(9 VAC 5-80-1200 and 9 VAC 5-50-30 G)

NOTIFICATIONS

22. **Initial Notifications** - The permittee shall furnish written notification to the DEQ of:

    a. The actual date on which modification of the boilers (Ref. 003 and 004) commenced within 30 days after such date.

    b. The actual start-up date of the boilers (Ref. 003 and 004) within 15 days after such date.

    c. The anticipated date of performance tests of the two boilers (Ref. 003 and 004) postmarked at least 30 days prior to such date.

    d. The anticipated date of continuous monitoring system performance evaluations postmarked not less than 30 days prior to such date.

    (9 VAC 5-50-50 and 9 VAC 5-80-1180)

GENERAL CONDITIONS

23. **Permit Invalidation** – The portions of this permit to modify the electric power generating facility shall become invalid, unless an extension is granted by the DEQ, if:

    a. A program of continuous construction or modification is not commenced within 18 months from the date of this permit.

    b. A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of a phased construction project.

    (9 VAC 5-80-1210)

24. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

    a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9 VAC 5-170-130 and 9 VAC 5-80-1180)

25. **Records of Malfunctions** - The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record. Records of malfunction shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9 VAC 5-20-180 J and 9 VAC 5-80-1180 D)

26. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish written notification to the DEQ, of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour. Such notification shall be made as soon as practicable but not later than four daytime business hours after the malfunction is discovered. . The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. Permittees subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the DEQ in writing.
(9 VAC 5-20-180 C and 9 VAC 5-80-1180)

27. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I and 9 VAC 5-80-1180)

28. **Maintenance/Operating Procedures** – At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the

affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment, monitoring devices, and process equipment which affect such emissions:

a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures. The permittee shall maintain records of the training provided, including the names of trainees, the date of training and the nature of the training.

(9 VAC 5-50-20 E and 9 VAC 5-80-1180 D)

29. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

a. Knowingly makes material misstatements in the application for this permit or any amendments to it;

b. Fails to comply with the conditions of this permit;.

c. Fails to comply with any emission standards applicable to a permitted emissions unit;

d. Causes emissions from this facility which result in violations of, or interferes with the attainment and maintenance of, any ambient air quality standard; or

e. Fails to operate this facility in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect on the date that the application for this permit is submitted.

(9 VAC 5-80-1210 G)

30. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the DEQ, of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1240)

31. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1180)

SOURCE TESTING REPORT FORMAT

Report Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Test Dates.
4. Tester; name, address and report date

Certification
1. Signed by team leader/certified observer (include certification date)
2. Signed by responsible company official
3. *Signed by reviewer

Copy of approved test protocol

Summary
1. Reason for testing
2. Test dates
3. Identification of unit tested & the maximum rated capacity
4. *For each emission unit, a table showing:
   a. Operating rate
   b. Test Methods
   c. Pollutants tested
   d. Test results for each run and the run average
   e. Pollutant standard or limit
5. Summarized process and control equipment data for each run and the average, as required by the test protocol
6. A statement that test was conducted in accordance with the test protocol or identification & discussion of deviations, including the likely impact on results
7. Any other important information

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Sampling port location and dimensioned cross section Attached protocol includes: sketch of stack (elevation view) showing sampling port locations, upstream and downstream flow disturbances and their distances from ports; and a sketch of stack (plan view) showing sampling ports, ducts entering the stack and stack diameter or dimensions

Test Results
1. Detailed test results for each run
2. *Sample calculations
3. *Description of collected samples, to include audits when applicable

Appendix
1. *Raw production data
2. *Raw field data
3. *Laboratory reports
4. *Chain of custody records for lab samples
5. *Calibration procedures and results
6. Project participants and titles.
7. Observers' names (industry and agency)
8. Related correspondence
9. Standard procedures

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* Not applicable to visible emission evaluations

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

Valley Regional Office

INTRA-AGENCY MEMORANDUM

4411 Early Road - P. O. Box 3000 Harrisonburg, VA 22801-3000

Permit Writer	[illegible]		**Date**	5/24/13
Air Permit Manager	[illegible]		**Date**	5/24/13
Memo To	Air Permit File			
Facility Name	Virginia Electric and Power Company – Bremo Power Station			
Registration Number	40199			
County-Plant I.D.	065-0001			
UTM Coordinates (Zone 17)	739.16	**Easting (km)**	4176.97	**Northing (km)**
Elevation (feet)	220			
Distance to Nearest Class I Area (select one)	~65	**SNP (km)**	—	**JRF (km)**
FLM Notification Required (Y/N)	N			
AFS Classification (A, SM, B)	A	**Before permit action**	A	**After permit action**
Pollutants for Which the Source is Title V Major	PM-10, NO_x, SO_2, CO, and GHGs	**Before permit action**	NO_x, CO, and GHGs	**After permit action**
PSD Major Source (Y/N)	Y	**Before permit action**	Y	**After permit action**
Pollutants for Which the Source is PSD Major	PM-10, NO_x, SO_2, CO	**Before permit action**	NO_x and CO	**After permit action**

I. Introduction

Bremo Power Station (Bremo) is a coal-fired electric production facility owned by Dominion Power and Electric Company (Dominion). It is located at 1038 Bremo Road in Bremo Bluff, on the north bank of the James River in Fluvanna County. The existing power station consists of two Babcock & Wilcox (B&W) pulverized coal wall-fired boilers and ancillary equipment. The boilers currently burn coal and distillate oil. The facility currently has a minor New Source review permit for its coal preparation materials, dated February 26, 2002. It also has a Title IV permit for acid rain sources, and a Title V permit for emissions greater than the federal operating permit threshold of 100 tons per year for nitrogen oxides and carbon monoxide (CO).

On June 19, 2012, DEQ received an Article 6, minor New Source Review application from Dominion to convert the existing facility from coal-fired, with a small amount of No. 2 fuel used for start-up, to a facility with a fuel stream consisting of 100% natural gas. Previous to the Article 6 submission, Dominion submitted a Prevention of Significant Deterioration (PSD) air permit application for the Bremo Power Station on July 15, 2011. On May 29, 2012, Dominion withdrew the PSD application. Amended pages of the Form 7, dated April 4, 2013, were received on April 22, 2013.

The conversion will require alteration to the two existing 1950's era balanced-draft, pulverized, coal-fired boilers (Units 003 and 004), the replacement of the auxiliary boiler, the addition of a gas pipeline heater, and the retirement of all coal and ash handling equipment (except for ash storage). The conversion of Bremo from coal to natural gas is a requirement in Condition 30 of Dominion's Virginia City Hybrid Energy Center's Prevention of Significant Deterioration (PSD) air permit.

The proposed conversion will result in a decrease in nitrogen oxides (NOx), sulfur dioxides (SO2), particulate matter (PM-10 and PM 2.5) and greenhouse gases (CO2e). Potential emissions after the conversion represent an emission increase with respect to Virginia's Article 6 regulations in 9 VAC 5-80-1105, for CO and volatile organic compounds (VOC).

Dominion will also be accepting a federally enforceable limitation on operations to a level which will result in a CO emissions increase that is below PSD significant emissions threshold of 100 tpy. With the limitation on operations, the increase in VOC emissions will be below 10 tpy. As a result of the operations limitation this project is not subject to PSD regulations; however, it is subject to Virginia's Minor New Source Review regulations.

II. Emission Units / Process Descriptions

Bremo Power Station currently has the following air emission equipment on site, which includes fuel burning equipment, and a coal handling system. The fuel burning equipment is as follows:

- Babcock and Wilcox Boiler (Unit 3), a pulverized coal-fired boiler, rated at 912 MMBtu/hr
- Babcock and Wilcox Boiler (Unit 4), a pulverized coal-fired boiler, voluntarily retrofitted with low NOx burners, rated at 1,699 MMBtu/hr
- Kewanee Package Boiler, distillate oil and propane fired, rated at 8.693 MMBtu/hr
- Solar Combustion Turbine, kerosene and distillate oil-fired, rated at 5.24 MMBtu/hr (used as back-up generator)
- Coal and ash handling equipment

Dominion proposes the following project:

<u>Convert boilers #3 and #4 into solely natural gas-fired units</u>
Dominion proposes to shutdown the two existing coal-fired boilers, and convert them to two natural gas-fired boilers. Following the conversion, Unit 3 will have a maximum rated input heat capacity of 920 MMBtu/hr; unit 4 will have a maximum rated input heat capacity of 1,684 MMBtu/hr. The planned air pollution control equipment for the facility are low-NOx burners and enhanced over-fire air for NOx emissions, and good work practices such as the maximization of combustion efficiency. No co-firing of either coal or No. 2 fuel is planned following the conversion of Units 3 and 4. Emissions of concern from each boiler are particulate matter (PM), particulate matter with an aerodynamic diameter of less than 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of less than 2.5 microns ($PM_{2.5}$), nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur dioxide (SO_2).

<u>Retire Coal and ash handling equipment</u>
Dominion will retire all coal and ash handling equipment in place.

<u>Shutdown 8.7 MMBtu/hr Kewanee Package Boiler</u>
The 8.7 MMBtu/hr Kewanee package boiler will be replaced with a 25.0 MMBtu/hr auxiliary boiler.

<u>Add 25.0 MMBtu/hr Auxillary Boiler</u>
Add 25.0 MMBtu/hr natural gas-fired auxiliary boiler as a replacement for the distillate oil-fired 8.7 MMBtu/hr boiler.

<u>Add Gas Pipeline Heater</u>
Add a natural gas pipeline heater rated at 4.277 MMBtu/hr.

III. Regulatory Review

A. 9 VAC 5 Chapter 80, Article 6 – Minor New Source Review

Minor NSR permitting applicability is based on the uncontrolled emission rate increase (UEI) of criteria pollutants for the project as defined in the Regulations. The UEI for criteria pollutants is evaluated as the sum of the new uncontrolled emissions (NUE) increases less the current uncontrolled emissions (CUE), or UEI = NUE – CUE. The UEI is then compared to the criteria pollutant exemptions levels in 9 VAC 5-80-1105. If the UEI exceeds the exemption level for any one criteria pollutant, the source is subject to the permitting requirements of 9 VAC 5 Chapter 80, Article 6.

NUE for the proposed boiler modification is calculated based on the combined total uncontrolled emissions from each piece of equipment to be physically or operationally modified. The UEI is set forth in Table 1 below. The NUE is the maximum emissions, at 8760 hours, from the large boilers while firing natural gas. The auxiliary boiler and the pipeline heater are both exempt from permitting based on their individual size as external fuel combustion units using gaseous fuel with a maximum heat input of less than 50 MMBtu/hr, per 9 VAC 5-80-1105 B.1.a(4).

The CUE is the current maximum emissions from the two large boilers while firing coal. The emission factors for coal were provided by Dominion, as obtained from AP-42, Section 1-4.

Table 1: UEI for Bremo Modification Project

Pollutant	NUE (tons/yr)	CUE (tons/yr)	UEI = NUE- CUE (tons/yr)	Exemption Level[1] (tons/yr)	Permitting Applicable?
PM	84.40	45630.36	-45545.96	15	NO
PM-10	84.40	11093.09	-11008.69	10	NO
PM-2.5[2]	84.40	11093.09	-11008.69	6	NO
SO_2	9.47	17039.91	-17030.44	10	NO
CO	684.33	228.72	**455.61**	100	YES
NO_x	1784.59	9835.11	-8050.53	10	NO
VOC	45.62	27.45	**18.18**	10	YES

1 – Exemption levels for criteria pollutants taken from 9 VAC 5-80-1105 D for projects.
2 – In absence of specific emission factors for PM-2.5, PM-2.5 assumed to have the same value as PM-10, as a conservative estimate.

Given that the UEI is above the permitting exemption thresholds in 9 VAC 5-80-1105.D.1 for a project at a stationary source, the project encompassing modification of the two boilers is subject to permitting.

B. 9 VAC 5 Chapter 80, Article 8 – PSD Major New Source Review

As a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input, Bremo is a named major stationary source in 9 VAC 5-80-1615 C.

Table 2 shows the emission increase (EI) for the proposed project. As indicated in said table, the proposed modification does not result in a significant emission increase, i.e., the increases do not exceed the given thresholds in 9 VAC 5-80-1700. Therefore, the proposed project is not subject to PSD permitting.

The facility has requested a combined limit for both boilers (003 and 004). As such, the PTE and BAE for boilers 003 and 004 reflect combined emissions for both units. A condition in the proposed permit (Condition 11) is included to indicate that from now on these boilers (003 and 004) will be treated as one emission unit; modification of one boiler will equate to modification of both boilers.

Table 2: Emission Increases for PSD Applicability

	Potential to Emit (PTE)[1] (tpy)				Baseline Actual Emissions (BAE) for 003 and 004, tpy (2009-2010) [3]	SEI = PTE-BAE (tpy)	PSD Significant Emissions Threshold (tpy)	Significant Change? (Yes or No)
	003 and 004	Aux Boiler 005	Pipeline Heater 006	Total				
PM (total)	24.2	1.095	0.19	25.47	406.91	-381.44	25	NO
PM-10	24.2	1.095	0.19	25.47	406.99	-381.52	15	NO
PM-2.5	24.2	1.095	0.19	25.47	29.66	-4.19	10	NO
SO_2	2.7	0.091	1.55E-02	2.82	7,355.63	-7,352.81	40	NO
NOx	522.9	3.631	0.62	527.2	1,955.84	-1,428.65	40	NO
CO[2]	196.1	4.052	0.69	200.8	103.88	97.00	100	NO
VOC	13.1	0.548	9.37E-02	13.72	12.42	1.30	40	NO
H_2SO4	0.054	1.86E-03	3.18E-04	0.06	147.1	-147.04	7	NO
Fluorides	--	--	--	--	31.0	-30.95	3	NO
Pb	0.002	5.30E-05	9.07E-06	1.64E-03	0.04	-0.03	0.6	NO
Grnhse (CO_2)	379,862	12,723.90	2176.80	394,762.61	1,524,973.2	-1,130,210.59	NA	NA
Grnhse (CH_4)	7.2	2.41E-01	4.12E-02	7.47	8.3	-0.78	NA	NA
Grnhse (N_2O)	2.0	6.57E-02	1.12E-02	2.04	6.2	-4.16	NA	NA
GHGs (Mass)	379,871	12,724.2	2,176.9	394,772.12	1,524,987.7	-1,130,215.53	NA	NO
Grnhse (CO_{2e})	380,621	12,749.33	2,181.15	395,551.46	1,527,068.5	-1,131,516.99	75,000	NA

[1] – See detailed calculations in Attachment A.

[2] – The facility has taken combined limits of 196.1 tpy for the two boilers to avoid PSD applicability. With these combined limits, the emission increase (EI) would be 97.0 tpy as shown in Equation 1, which follows on the next page.

[3] – Baseline Actual Emissions (BAE) for 003 and 004 are defined as occurring within the five-year period immediately preceding when the owner begins actual construction of the project. Construction of the project is scheduled for December 2013, therefore the BAE are calculated using emissions data from the 12-month calendar years 2009 and 2010.

The calculations for CO are based on the following Equation 1:

$CO_{increase} = CO\ Limit_{003\&004}\ (tpy) + CO_{Auxboiler} + CO_{GasHeater} - BAE$ (Equation 1)

Where:

$CO\ Limit_{003\&004}$ = CO Limit Combined Boiler 003 plus Boiler 004 Annual Emissions Limit after Conversion (tpy)

BAE = Baseline Actual Emissions from Existing Boilers 003 and 004 (tpy), using 2009 – 10 as the baseline year. Baseline Actual Emissions (BAE) for 003 and 004 are defined as occurring within the five-year period immediately preceding when the owner begins actual construction of the project (see 9 VAC 5-80-1615). Construction of the project is scheduled for December 2013; therefore the BAE are calculated using emissions data from the 12-month calendar years 2009 and 2010.

$CO_{increase}$ = 97.0 tpy CO (allowable CO emission increase to stay under PSD significance emissions increase)

$CO_{Auxboiler}$ = New Auxiliary Boiler Max Potential CO Emissions (tpy)

$CO_{GasHeater}$ = New Gas Heater Max Potential CO Emissions (tpy)

In order to stay under the PSD threshold for CO emissions of 100 tpy, the total CO allotment for boiler Units 003 and 004 is 196.14 tpy. Solving equation (1) to determine the CO limit needed to maintain a CO emission rate of not greater than a 97.0 tpy increase results in:

$CO\ Limit_{003\&004}$ = 196.1 tpy

C. <u>9 VAC 5 Chapter 50, Part II, Article 5 - NSPS</u>

<u>40 CFR 60, Subpart Da, Standards of Performance for Utility Steam Generating Units</u>

Units 003 and 004 are not subject. 40 CFR 60 Subpart Da regulates fossil-fuel fired boilers in excess of 250 MMBtu/hr for which construction, modification, or reconstruction occurred after September 18, 1978. Since Units 3 and 4 were constructed in the 1950's, neither boiler was "constructed" after September 18, 1978. The conversion to natural gas does not increase emissions of any pollutant to which Subpart Da applies, meaning it is not a "modification" as described in 40 CFR 60 .14 (a), (b), and (h). Because the fixed capital cost does not exceed 50 percent of the fixed capital cost that would be required to construct a comparable new facility, it is also not a "reconstruction" as described in 40 CFR 60.15(b)(1).

As a result, the fuel conversion does not represent construction, reconstruction or a modification to the boilers in accordance with 40 CFR 60 Subpart Da and, therefore, the boilers will not be subject to the Subpart Da.

40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial and Commercial Steam Generating Units

Unit 005 is subject to notification requirements. The auxiliary boiler is of a size that is subject to Subpart Dc standards. Although none of the emission standards identified in Subpart Dc apply to boilers solely fueled by natural gas, the boiler is still subject to the requirement to notify EPA and the DEQ of the dates when construction is commenced on the auxiliary boiler, and when initial startup occurs, per 40 CFR 60.48(c) records.

40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants

No units in project are subject. Since the use of coal is being completely eliminated, NSPS Subpart Y for coal preparation plants does not apply to this project.

D. 9 VAC 5 Chapter 60, Part II, Article 1 - NESHAPS

There are no NESHAPS requirements at this facility.

E. 9 VAC 5 Chapter 60, Part II, Article II - MACT

40 CFR 63 Subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers

Units 003, 004, and 005 are not subject. Boilers 003, 004 and 005 will only burn natural gas, which is not affected by this rule.

40 CFR 63, Subpart UUUUU, National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil- Fired Electric Utility Stream Generating Units

Units 003 and 004 are not subject. On February 16, 2012, the EPA promulgated Subpart UUUUU of 40 CFR 63. These standards apply to coal and oil-fired steam electric generating units over 25 MW at both major and minor HAP sources. However, natural gas-fired steam electric units are not subject to Subpart UUUUU. A unit is a gas-fired unit as long as it does not burn coal or oil for more than 10.0 percent of the average annual heat input during any consecutive calendar year or for more than 15 percent of the annual heat input during one calendar year. EPA concluded that regulation of HAP from gas-fired electric utility steam generating units is not appropriate or necessary.

F. 9 VAC 5, Chapter 40 – Article IV - Existing Emission Standards

Rule 4-8 – Emission Standards for Fuel Burning Equipment

The emission limits in the permit are equal to or more stringent than the existing emissions standards.

IV. Best Available Control Technology Review (BACT) (9 VAC 5-50-260)

Pursuant to 9 VAC 5-50-260, a project shall include BACT for each regulated pollutant where there is an increase in the uncontrolled emission rate equal to or greater than the levels in 9 VAC 5-80-1105 D. This requirement applies to each affected emissions unit in the project. BACT applies to CO and VOC for the boilers 003 and 004 since the criteria pollutant emissions for **CO** and **VOC** are greater than the levels in 9 VAC 5-80-1105 D, as shown in Table 1.

Table 3: BACT for the Natural Gas-Fired Boilers (003 and 004)

Pollutant	Proposed Control Technology
CO	Low NOx burners using enhanced overfire air (combustion control technique)
	Emission concentration not to exceed 0.06 lb/MMBtu
	Combined limits of 196.1 tpy
	Good combustion practices
VOC	Good combustion practices
	Emission concentration not to exceed 0.004 lb/MMBtu

The facility investigated potential installation of an oxidation catalyst (OC) as BACT for the boilers 003 and 004. As indicated in the letter dated October 23, 2012, the facility determined that the installation of the OC will result in the formation of visible emissions, manifested via a brown plume.

The formation of a brown plume is a function of NO_2 concentrations in the flue gas. NO_2 typically consists of nitrogen oxide (NO) and NO_2. For natural gas combustion during normal operations, the NO_2 concentrations are typically below levels where brown plume (i.e. visible emissions) is expected to be visible. While the CO catalyst does not create additional NOx, it will convert a significant portion of the NO to NO_2 as flue gas passes through the catalyst. This increase in NO_2 concentrations will be significant enough to allow the formation of brown plume, resulting in visible emissions as outlined in the attached Sergent & Lundy report (Attachment B – Bremo Bluff Natural Gas Conversion – Brown Plume Study, Revision 1 (October 19, 2012)).

In order to mitigate visible emission resulting from the formation of brown plume, the facility indicated that it is necessary to limit NOx from the boiler.

Dominion submitted a cost analysis for control of CO which includes installation of selective catalytic reduction (SCR) to mitigate brown plume formation. This analysis indicated that installation of the oxidation catalyst is economically infeasible. The facility proposed the items in Table 3, above, as BACT for CO and VOC from boilers 003 and 004. Even in the absence of an OC for boilers 003 and 004, the proposed short-term emission limits for CO are lower than BACT determinations for similar units (gas-fired electric utility steam generating units (EUSGUs)) with heat inputs greater than 500 MMBtu/hr listed in the RACT/BACT/LAER Clearinghouse (RBLC) database (Attachment C – Summary of RACT/BACT/LAER Clearinghouse data). There are two facilities listed in the RBLC that have a lower emissions rate and no add-on control; however, both of these units are auxiliary boilers and not EUSGUs. Additionally, a notation in the RBLC record for one of the auxiliary boilers states that the emissions rate is a case-by-case MACT determination and is more stringent than the BACT determination for the unit.

Similarly, the VOC control method used by large natural gas-fired boilers listed in the RBLC, with one exception, is good combustion practices. One unit employs catalytic oxidation for VOC control. As demonstrated above, catalytic oxidation has been found to be infeasible for the Bremo facility. Nonetheless, the proposed VOC emission rates for Bremo (3.68 and 6.74 lbs/hr for 81 MW and 172 MW units, respectively) are proportionally lower than the rate for the unit employing catalytic oxidation (5.5 lbs/hr for 82 MW).

Accordingly, DEQ agrees that BACT for CO and VOC would be as described in Table 3 above.

As discussed in Section B above, the facility has taken a combined limit for boiler units 003 and 004. The combined CO emission limit for both boilers is 196.1 tpy, as indicated in Condition 10 of the proposed permit. As a result of this combination on annual emission limits, a modification to one of these boiler units (003 and 004) equates to a modification of both boilers. If PSD is triggered in any future modifications, both boilers will be subject to BACT.

V. Summary of Permitted Allowable Emissions (Increases/Decreases)

Table 4, below, provides a summary of the facility's potential emissions. Detailed calculations are contained in Attachment A.

Table 4: Summary of Potential Emissions (Increases/Decreases, tpy) for Bremo Modification

Pollutant	Current PTE[1] (coal)	Future PTE (Individual Units) NG		Future PTE	Delta (FPTE – CPTE)	Modeling Exemption Level (tpy)
		Boilers 003 & 004	Boiler & Heater 005 & 006	Total Emissions		
PM	1,650.3	24.2	1.3	25.5	-1,624.8	25
PM-10	1647.6	24.2	1.3	25.5	-1,622.1	15
PM-2.5	1636.7	24.2	1.3	25.5	-1,611.2	10
SO_2	30,292.0	2.7	0.11	2.8	-30,289.2	40
CO	229.5	196.1	4.7	200.9	-28.6	100
NOx	5,278.2	522.9	4.3	527.2	-4,751.0	40
VOC	27.5	13.1	0.64	13.7	-13.8	40

[1] – Current PTE based on multiplying hourly emission limits in Title V permit, dated 01/01/08, by 8760 hrs/yr.

Following, in Table 5, is the maximum fuel consumption for each of the Bremo utility boilers. The boilers' individual maximum annual operational hours is listed along with their corresponding fuel usage, when operating singly. The annual fuel throughput contained in the permit is equivalent to the combined CO limit of 196.1 tpy for the two boilers to avoid PSD applicability. With these combined limits, the emission increase (EI) would be 97.0 tpy. See calculations. However, due to differences in the NOx emission factors for boilers 003 and 004, the annual NOx emission limitations in the permit for boilers 003 and 004 are based on the worst-case scenario (Boiler 003 operating at 7105.1 hours per year). Boiler 004 is unable to reach the NOx limit without first exceeding the other annual emission limitations contained in the permit.

Table 5 – Natural Gas Fuel Consumption (Units 003 and 004)

Unit	Capacity (MMBtu/hr)	Max Operation 1 Unit in Operation (hrs/yr)	Max. Fuel Consumption 1 Unit in Operation ($MMft^3/yr$)	Combined Operation ($MMft^3/yr$)
004	1684	3881.6	6330	6330
		OR	OR	
003	920	7105.1	6330	

VI. Dispersion Modeling

Criteria Pollutants

As shown in Table 5 above, the controlled emission increases of criteria pollutants are below the modeling thresholds contained in the *DEQ New Source Review Permits Program Manual (September 7, 2000 as revised November 16, 2001 and April 1, 2002)* for all pollutants.

Toxic Pollutants

The proposed boilers burn natural gas only; therefore, in accordance with 9 VAC 5-60-300 C.7, hazardous air pollutants (HAP) are not evaluated for minor NSR permitting.

VII. Boilerplate Deviations

Boilerplates included in drafting this permit are the Skeleton_NSR_BP_911510 VRO, Generic_BP_091510 VRO, "Testing", "NG-DO (September 2008)", and "CEMS". There were no significant deviations from the boilerplates; however, a condition defining periods of start-up and shutdown was added to the permit to clarify emissions during those periods.

VIII. Compliance Demonstration

Compliance with the permit will be demonstrated by:

- CEMS on CO and NO_x emissions
- Initial opacity test on both boilers
- Initial testing for NO_x, VOC and CO, PM_{10} and $PM_{2.5}$ emissions, as indicated in the permit.
- Continuance of testing for opacity and criteria pollutants as deemed necessary by DEQ.
- Records of bypass, malfunctions, shutdown or failure of the facility and its associated air pollution control equipment.

IX. Title V Review - 9 VAC 5 Chapter 80, Article 1

As a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input, Bremo meets the definition of major stationary source in 9 VAC 5-80-60. Therefore, the facility is subject to permitting under the Title V operating permit program. It has a Title V permit, which was allowed to expire in December 2012, pending the conversion of the coal-fired boilers to natural gas.

Table 6 lists the allowable emissions from the facility for Title V applicability following the modification of the boiler units 003 and 004, along with the installation of the auxiliary boiler and the pipeline heater. Dominion has stated that it intends to shut down the coal handling equipment before the modified boilers are placed into operation. Therefore the emissions from the coal handling equipment are not listed.

Table 6: Facility-Wide Emissions for Title V Permitting Applicability (tpy) After Permit Issuance

Pollutant	PM-10	PM-2.5	SO_2	CO	NOx	VOC
Existing Turbine, 4.2 MMBtu/hr (Ref. 002)[1]	8.8	-	60.6	-	-	-
920 MMBtu/hr Boiler (Ref. 003) 1684 MMBtu/hr Boiler (Ref. 004)	24.2	24.2	2.7	196.1	522.9	13.1
25.0 MMBtu/hr Boiler (Ref. 005)	1.1	1.1	0.1	4.1	3.6	0.5
Pipeline Heater (Ref. 006)	0.2	0.2	0.0	0.7	0.6	0.1
Total	**34.3**	**25.5**	**63.4**	**200.9**	**527.2**	**13.7**

[1] - Annual emissions for the turbine are extrapolated, to 8760 hours, from the hourly emission limits listed in facility's Title V permit, dated August 18, 2008.

X. Site Suitability

Not Applicable

XI. Public Participation

No public participation is required as a result of this permitting action.

XII. Permit Fee

There is no applicable fee for the permitting action. The initial Article 6 application for this facility was received by the DEQ in June 2012, prior to the initiation of permit application fees.

XIII. Other Considerations

A. CEDS

Table 7 lists the following related CEDS entries for this facility. The listed permitting actions were referenced during the preparation of this draft permit.

Table 7: Previous Relevant Permit Applications for this Facility

CEDS Number	Date of Action	Action
2	02/26/02	mNSR – Coal and Ash Handling System
11	01/01/08	Title V renewal
15	08/20/08	Title V Minor mod.

B. Equipment Shutdown

Dominion has indicated in its permit application that it will retire all of its coal handling equipment in place. This equipment is permitted in a February 26, 2002 permit. As such, Dominion will have to enter into a formal shutdown agreement with DEQ.

XIV. Recommendations

Recommend permit issuance.

Attachments

Attachment A – Emissions Calculations
Attachment B – Correspondence Regarding Brown Plume Emissions
Attachment C – RBLC Data Table for Carbon Monoxide BACT

Attachment A

Emission Calculations

Source: Dominion - Bremo (Facility Fuel Modification Project), CEDS #19
Registration Number: 40199
Criteria Pollutant Permitting Applicability - Natural Gas

Uncontrolled Emisson Increase (UEI) = New Uncontrolled (NU) - Current Uncontrolled (CU)

Natural Gas (Boiler Unit 3)

Max. Heat Input (rating):	920	MMBtu/hr (Unit 3)
	8059200	MMBtu/yr (Unit 3)
Fuel Heat Content (HHV):	1032.7	BTU/ft³ (taken from facility application, 11/26/12)
Potential Fuel Usage Rate:	890.87	Mft³/hr
	0.891	MMft³/hr
	7804	MMft3/yr
Max operational hrs/year	8760	

Pollutant	Emission Factor	Emission Factor	920 MMBtu/hr Fuel Consumption	Emissions	
	(lb/MMBtu)	(lb/MMft3)	(MMft³/hr)	(lbs/hr)	(tons/yr)
PM (filterable) [a]			0.891	0.00	0.00
PM (condensable) [a]			0.891	0.00	0.00
PM (total) [a]	0.0074	7.6	0.891	6.81	29.8
PM-10 [a]	0.0074	7.6	0.891	6.81	29.8
PM-2.5 [a]	0.0074	7.6	0.891	6.81	29.8
SO2 [a]	0.00083	0.9	0.891	0.76	3.3
CO [a]	0.06	62.0	0.891	55.20	241.8
NOx [a]	0.15	154.9	0.891	138.00	604.4
VOC [a]	0.004	4.1	0.891	3.68	16.1
H2SO4 [b]	0.0000166	0.0	0.891	0.02	0.067
Fluorides [c]	negligible	--	0.891	--	--
Pb [d]	4.84E-07	0.00050	0.891	0	0.001950
Grnhse (CO2)	116.2	119999.7	0.891	106,904	468240
Grnhse (Ch4)	0.0022	2.3	0.891	2.02	8.9
Grnhse (N2O)	0.0006	0.6	0.891	0.55	2.4
Grnhse (CO2e)	116.44	120247.6	0.891	107,125	469207

Notes:

a - Emission factor taken from facility application, based on vendor estimate (uncontrolled).
b - Assumed to be 2% of SO2 (footnote b in table 1.1-3 of AP-42)
c - No factor in AP-42, Chapter 1.4 (7/98).
d - table 1.4-2 of AP-42
e - sum of CO2, CH4, and N2O. CH4 assumed to have 21 and N2O assumd to have 310 times the trapping capability of CO2.

Sample Calculation - PM-10

0.0074 lb/MMBtu * 1032.7 MMBtu/MMcf * 1.631 MMCF/hr =	6.81	lb/hr

Fuel Conversion Calculations

7,804 MMCF/yr * 1032.7 MMBtu/MMCF
= 8059.2 MMCF/year

Natural Gas (Boiler Unit 4)

Max. Heat input (rating):	1684	MMBtu/hr
	14751840	MMBtu/yr
Fuel Heat Content (HHV):	1032.7	BTU/ft^3 (per facility application, 11/26/12)
Potential Fuel Usage Rate:	1630.68	Mft^3/hr
	1.631	MMft^3/hr
	14285	MMft3/yr
Max operational hrs/year	8760	

Pollutant	Emission Factor	Emission Factor	Unit 4 = 1684 MMBtu/hr Fuel Consumption	Emissions	
	(lb/MMBtu)	(lb/MMft3)	(MMft^3/hr)	(lbs/hr)	(tons/yr)
			1.631	0.00	0.00
			1.631	0.00	0.00
PM (total) [a]	0.0074	7.6	1.631	12.46	54.58
PM-10 [a]	0.0074	7.6	1.631	12.46	54.58
PM-2.5 [a]	0.0074	7.6	1.631	12.46	54.58
SO2 [a]	0.00083	0.9	1.631	1.40	6.12
CO [a]	0.06	62.0	1.631	101.04	442.56
NOx [a]	0.16	165.2	1.631	269.44	1180.15
VOC [a]	0.004	4.1	1.631	6.74	29.50
H2So4	0.0000166	0.0	1.631	0.03	0.12
Fluorides	negligible	--	1.631	--	--
Pb	4.84E-07	0.00050	1.631	0.0008	0.00
Grnhse (CO2)[d]	116.2	119999.7	1.631	195,681	857081.90
Grnhse (CH4)[d]	0.0022	2.3	1.631	3.70	16.23
Grnhse (N2O)[d]	0.0006	0.6	1.631	1.01	4.43
Grnhse (CO2e)[e]	116.44	120247.6	1.631	196,085	858852.12

Notes:

a - Emission factor taken from facility application, based on vendor estimate (uncontrolled).

b - Assumed to be 2% of SO2 (footnote b in table 1.1-3 of AP-42)

c - No factor in AP-42, Chapter 1.4 (7/98).

d - table 1.4-2 of AP-42

e - sum of CO2, CH4, and N2O. CH4 assumed to have 21 and N2O assumd to heve 310 times the trapping capability of CO2.

Natural Gas (Auxiliary Boiler) - Unit 005

Max. Heat Input (rating):	25	MMBtu/hr
	219000	MMBtu/yr
Fuel Heat Content (HHV):	1032.7	BTU/ft^3 (taken from facility application, 11/26/12)
Potential Fuel Usage Rate:	24.21	Mft^3/hr
	0.024	MMft^3/hr (@ max hrs = 8760 hrs/yr)
	212	MMft3/yr
Max operational hrs/year	8760	

Pollutant	Emission Factor	Emission Factor	32.7 MMBtu/hr		
			Fuel Consumption	Emissions	
	(lb/MMBtu)	(lb/MMft3)	(MMft^3/hr)	(lbs/hr)	(tons/yr)
			0.024	0.00	0.00
			0.024	0.00	0.00
PM (total) [a]	0.01	10.3	0.024	2.50E-01	1.1
PM-10 [a]	0.01	10.3	0.024	2.50E-01	1.1
PM-2.5 [a]	0.01	10.3	0.024	2.50E-01	1.1
SO2 [a]	0.00083	0.9	0.024	2.08E-02	9.09E-02
NOx [a]	0.03316	34.2	0.024	8.29E-01	3.6
CO [b]	0.037	38.2	0.024	9.25E-01	4.1
VOC [a]	0.005	5.2	0.024	1.25E-01	5.48E-01
H2SO4 [b]	0.000017	1.8E-02	0.024	4.25E-04	1.86E-03
Fluorides [c]	negligible	--	0.024	--	--
Pb [d]	4.84E-07	0.00050	0.024	1.21E-05	5.30E-05
GHGs (Mass)	--	--	0.024	2,905.07	12,724.21
Grnhse (CO2)[e]	116.2	119999.7	0.024	2905.00	12723.9
Grnhse (Ch4)[e]	0.0022	2.3	0.024	5.50E-02	2.41E-01
Grnhse (N2O)[e]	0.0006	0.6	0.024	1.50E-02	6.57E-02
Grnhse (CO2e)[e]	116.44	120247.6	0.024	2911.00	12,750.2

Notes:

a - Vendor estimate, 9 ppm NOx, @ 15% O2

b - Assumed to be 2% of SO2 (footnote b in table 1.1-3 of AP-42)

c - No factor in AP-42, Chapter 1.4 (7/98).

d - table 1.4-2 of AP-42

e - sum of CO2, CH4, and N2O. CH4 assumed to have 21 and N2O assumd to have 310 times the trapping capability of CO2.

Natural Gas (Pipeline Heater)

Max. Heat Input (rating):	4.277	MMBtu/hr		
	37466.52	MMBtu/yr		
Fuel Heat Content (HHV):	1032.7	BTU/ft^3 (taken from facility application, 11/26/12)		
Potential Fuel Usage Rate:	4.14	Mft^3/hr		
	0.004	MMft^3/hr (@ max hrs = 8760 hrs/yr)		
	21	MMft3/yr		
Max operational hrs/year	8760			

Pollutant	Emission Factor	Emission Factor	4.2 MMBtu/hr		
			Fuel Consumption	Emissions	
	(lb/MMBtu)	(lb/MMft3)	(MMft^3/hr)	(lbs/hr)	(tons/yr)
			0.004	0.00	0.00
			0.004	0.00	0.00
PM (total) [a]	0.01	87.6	0.004	4.28E-02	1.87E-01
PM-10 [a]	0.01	87.6	0.004	4.28E-02	1.87E-01
PM-2.5 [a]	0.01	87.6	0.004	4.28E-02	1.87E-01
SO2 [a]	0.00083	7.3	0.004	3.55E-03	1.55E-02
NOx [b]	0.03316	290.5	0.004	1.42E-01	6.21E-01
CO [b]	0.037	324.1	0.004	1.58E-01	6.93E-01
VOC [a]	0.005	43.8	0.004	2.14E-02	9.37E-02
H2SO4 [b]	0.000017	0.1	0.004	7.27E-05	3.18E-04
Fluorides [c]	negligible	--	0.004	—	—
Pb [d]	4.84E-07	0.0	0.004	2.07E-06	9.07E-06
GHGs (Mass)	—	—	0.004	497.0	2,176.9
Grnhse (CO2) [e]	116.2	1017912.0	0.004	496.99	2,176.8
Grnhse (CH4) [e]	0.0022	19.3	0.004	9.41E-03	4.12E-02
Grnhse (N2O) [e]	0.0006	5.3	0.004	2.57E-03	1.12E-02
Grnhse (CO2e) [e]	116.44	1020014.4	0.004	498.01	2,181.3

Notes:

a - Emission factor taken from facility application, based on vendor estimate (uncontrolled).

b - Assumed to be 2% of SO2 (footnote b in table 1.1-3 of AP-42)

c - No factor in AP-42, Chapter 1.4 (7/98).

d - table 1.4-2 of AP-42

e - sum of CO2, CH4, and N2O. CH4 assumed to have 21 and N2O assumd to have 310 times the trapping capability of CO2.

Coal (Boiler Unit 003) - Current Uncontrolled

Max. Heat Input (rating):	912	MMBtu/hr (Unit 3)
	7989120	MMBtu/yr (Unit 3)
Fuel Heat Content (HHV):	12529	Btu/lb
Potential Fuel Usage Rate:	72791.125	lb/hr coal consumed
Max operational hrs/year	8760	

Pollutant	Emission Factor	Emission Factor	1699 MMBtu/hr		
			Fuel Consumption	Emissions	
	(lb/MMBtu)		(lb/hr)	(lbs/hr)	(tons/yr)
			72,791	0.00	0.00
			72,791	0.00	0.00
PM (total) [a]	3.99	--	72,791	3,638.88	15,938
PM-10 [a]	0.97	--	72,791	884.64	3,875
PM-2.5 [a]	0.97	--	72,791	884.64	3,875
SO2 [a]	1.49	--	72,791	1,358.88	5,952
CO [b]	0.02	--	72,791	18.24	80
NOx [b]	0.86	--	72,791	784.32	3,435
VOC [b]	0.0024	--	72,791	2.19	10
H2SO4 [b]	0.0300000	--	72,791	27.36	120
Fluorides [c]	0.006	--	72,791	5.47	24
Pb [d]	1.60E-03	--	72,791	1.46	6
Grnhse (CO2) [d]	116.2	--	72,791	105,974.40	464,168
Grnhse (Ch4) [d]	0.0022	--	72,791	2.01	9
Grnhse (N2O) [d]	0.0006	--	72,791	0.55	2
Grnhse (CO2e) [d]	116.44	--	72,791	106,193.28	465,127

Notes:

a - Emission factors taken from facility application, based on AP-42, Section 1.1. PM-2.5 assumed as PM-10 as conservative est.

b - Assumed to be 2% of SO2 (footnote b in table 1.1-3 of AP-42)

c - table 1.1-18 of AP-42; adjusted to an uncontrolled rate assuming 99% control

d - Global warming potential (GWP) factor taken from EPA *PSD and Title V Permitting Guidance for Greenhouse Gases* (3/2011). Gases (3/2011). Also listed in facility application.

Sample Calculation (fuel conversion):

912 MMBtu/hr * lb/12529 Btu* 1E6 Btu/MMBtu = 72791 lb/hr
72791 lb/hr / 2E3 lb/ton = 36.4 ton/hr fuel (coal) consumed

Coal (Boiler Unit 004) - Current Uncontrolled

Max. Heat Input (rating):	1699	MMBtu/hr (Unit 4)
	14883240	MMBtu/yr (Unit 4)
Fuel Heat Content (HHV):	12,477	Btu/lb (2011 Emissions Inventory)
Potential Fuel Usage Rate:	136,171	lb/hr coal consumed
Max operational hrs/year	8760	

Pollutant	Emission Factor	Emission Factor	Unit 4 = 1699 MMBtu/hr Fuel Consumption	Emissions	
	(lb/MMBtu)		(lb/hr)	(lbs/hr)	(tons/yr)
	-		136,171	0.00	0.00
	-		136,171	0.00	0.00
PM (total) [a]	3.99	--	136,171	6,779.01	29,692
PM-10 [a]	0.97	--	136,171	1,648.03	7,218
PM-2.5 [a]	0.97	--	136,171	1,648.03	7,218
SO2 [a]	1.49	--	136,171	2,531.51	11,088
CO [b]	0.02	--	136,171	33.98	149
NOx [b]	0.86	--	136,171	1,461.14	6,400
VOC [a]	0.0024	--	136,171	4.08	18
H2SO4 [b]	0.0300000	--	136,171	50.97	223
Fluorides	0.006	--	136,171	10.19	45
Pb [c]	1.60E-03	--	136,171	2.72	12
Grnhse (CO2) [d]	116.2	--	136,171	197,423.80	864,716
Grnhse (CH4) [d]	0.0022	--	136,171	3.74	16
Grnhse (N2O) [d]	0.0006	--	136,171	1.02	4
Grnhse (CO2e) [d]	116.44	--	136,171	197,831.56	866,502

Notes:

a - Emission factors taken from facility application, based on AP-42, Section 1.4. PM-2.5 assumed as PM-10 as conservative est.

b - Assumed to be 2% of SO2 (footnote b in table 1.1-3 of AP-42)

c - table 1.1-18 of AP-42; adjusted to an uncontrolled rate assuming 99% control

d - Global warming potential (GWP) factor taken from EPA *PSD and Title V Permitting Guidance for Greenhouse Gases* (3/2011). Gases (3/2011). Also listed in facility application.

UEI = NU - CU

New Uncontrolled Emissions (Natural Gas fired)

Pollutant	003	004			total
	Unit Emissions (tpy)				
PM	29.82	54.58			84.40
PM-10	29.82	54.58			84.40
PM-2.5	29.82	54.58			84.40
SO2	3.34	6.12			9.47
CO	241.78	442.56			684.35
NOx	604.44	1,180.15			1784.59
VOC	16.12	29.50			45.62

Current Uncontrolled Emissions (Coal)

Pollutant	003	004	009 (New Unit)		total
	Unit Emissions (tpy)				
PM	15938.29	29692.06	0.0		45630.36
PM-10	3874.72	7218.37	0.0		11093.09
PM-2.5	3874.72	7218.37	0.0		11093.09
SO2	5951.89	11088.01	0.0		17039.91
CO	79.89	148.83	0.0		228.72
NOx	3435.32	6399.79	0.0		9835.11
VOC	9.59	17.86	0.0		27.45

Uncontrolled Emission Increase (UEI = NU - CU)

Pollutant	003	004	005	006	total
	Unit Emissions (tpy)				
PM	-15908.48	-29637.48	0.0	0.00	-45545.96
PM-10	-3844.90	-7163.79	0.0	0.00	-11008.69
PM-2.5	-3844.90	-7163.79	0.0	0.00	-11008.69
SO2	-5948.55	-11081.89	0.0	0.00	-17030.44
CO	161.88	293.72	0.0	0.00	455.61
NOx	-2830.88	-5219.65	0.0	0.00	-8050.53
VOC	6.53	11.64	0.0	0.00	18.18

** Note: Values for coal do not sum as indicated in Dominion application. The values here are drawn from the TV, 2011 emissions inventory, or NSR coal handling equipment permit.

Permitting Applicability - Large Boilers

Pollutant	Emission Factor		Boiler Unit 3 (920 MMBtu/hr)			Boiler Unit 4 (1684 MMBtu/hr)			Boiler Emissions (B3 + B4) Sum
			Fuel Consumption	Emissions		Fuel Consump.	Emissions		
	(lb/MMBtu)	(lb/MMCF)	(MMCF/hr)	(lbs/hr)	(tons/yr)	MMCF/hr	(lbs/hr)	(tons/yr)	(tons/yr)
			0.891	0.00	0.00	1.631	0.00	0.00	0.0
			0.891	0.00	0.00	1.631	0.00	0.00	0.0
PM (total)	0.0074	7.6	0.891	6.81	29.82	1.631	12.46	54.58	84.4
PM-10	0.0074	7.6	0.891	6.81	29.82	1.631	12.46	54.58	84.4
PM-2.5	0.0074	7.6	0.891	6.81	29.82	1.631	12.46	54.58	84.4
SO2	0.00083	0.9	0.891	0.76	3.34	1.631	1.40	6.12	9.5
NOx (Unit 4)	0.15	154.9	0.891	138.00	604.44	--	--	--	604.4
NOx (Unit 3)	0.16	165.2	--	--	--	1.631	269.44	1180.15	
CO	0.06	62.0	0.891	55.20	241.78	1.631	101.04	442.56	684.3
VOC	0.004	4.1	1.631	6.74	29.51	1.631	6.74	29.50	59.0

Fueling Scenarios for Boilers 003 and 004
Natural Gas (Proposed Increases)

There are three different fueling scenarios for Boilers 003 and 004.
Scenario #1 - Complete operation of Boiler 003 with NO operation of Boiler 004.
Scenario #2 - Complete operation of Boiler 004 with NO operation of Boiler 003.
Scenario #3 - Combined operation of Boilers 003 and 004 with a single fuel throughput limit (Scenarios #1 and #2 provide the worst-case emissions from each boiler 003 and 004); for this reason, only Scenario #1 and #2 are presented below.
Annual emissions for each scenario #1 and #2 result in the same annual emissions (aside from NOx) as shown below.

Scenario #1
Natural Gas (Boiler Unit 003) - Maximum Operation of Unit 003 (NO operation of Unit 004)

Max. Heat Input (rating):	920	MMBtu/hr (Unit 3)
	8059200	MMBtu/yr (Unit 3) - at 8760 hrs/yr
Fuel Heat Content (HHV):	1032.7	Btu/ft³ (taken from facility application, 11/26/12)
Potential Fuel Usage Rate:	890.87	Mft³/hr
	0.891	MMft³/hr
	6330	MMft3/yr (Calculation: 0.891 MMft3/hr * 7105 hr/year) = 6330 MMft³/yr)
Max operational hrs/year	7105	Max number of operational hrs possible to maintain CO increase at 97.0 tpy.

Pollutant	Emission Factor	Emission Factor	Unit 3 = 920 MMBtu/hr		
			Fuel	Emissions[f]	
	(lb/MMBtu)	(lb/MMft3)	(MMft³/hr)	(lbs/hr)	(tons/yr)
PM (total) [a]	0.0074	7.6	0.891	6.81	24.2
PM-10 [a]	0.0074	7.6	0.891	6.81	24.2
PM-2.5 [a]	0.0074	7.6	0.891	6.81	24.2
SO2 [a]	0.00088	0.9	0.891	0.76	2.7
CO [a]	0.06	62.0	0.891	55.20	196.1
NOx [a]	0.16	165.2	0.891	147.20	522.3
VOC [a]	0.004	4.1	0.891	3.68	13.1
H2SO4 [b]	0.0000166	0.0	0.891	0.02	0.1
Fluorides	negligible	--	0.891	--	--
Pb	4.84E-07	0.0	0.891	0.00	1.6E-03
Grnhse (CO2)	116.2	119,999.74	0.891	106,904.00	379780.3
Grnhse (CH4)	0.0022	2.3	0.891	2.02	7.2
Grnhse (N2O)	0.0006	0.6	0.891	0.55	2.0
Grnhse (Co2e)	116.44	120,247.59	0.891	107,124.80	380564.7

Notes:
a - Emission factor taken from facility application, based on vendor estimate (uncontrolled).
b - Assumed to be 2% of SO2 (footnote b in table 1.1-3 of AP-42)
c - No factor in AP-42, Chapter 1.4 (7/98).
d - table 1.4-2 of AP-42
e - Global warming potential factor taken from EPA *PSD and Title V Permitting Guidance for Greenhouse Gases* (3/2011). Also listed in facility application.
f - Emissions in bold are included as permit limits.

Scenario #2

Natural Gas (Boiler Unit 4) - Maximum Operation of Unit 004 (NO operation of Unit 003)

Max. Heat Input (rating):	1684	MMBtu/hr (Unit 4)
	14751840	MMBtu/yr (Unit 4) - at 8760 hrs/yr
Fuel Heat Content (HHV):	1032.7	BTU/ft³ (taken from facility application, 11/26/12)
Potential Fuel Usage Rate:	1630.68	Mft³/hr
	1.631	MMft³/hr
	6330	MMft3/yr (Calculation: 1.631 MMft3/hr * 3881.6 hr/year) = 6330 MMft³/yr).
Max operational hrs/year	3881.6	Max hrs possible to maintain CO increase @ 97.0 tpy.

Pollutant	Emission Factor	Emission Factor	1684 MMBtu/hr		
			Fuel Consumption	Emissions[f]	
	(lb/MMBtu)	(lb/MMft3)	(MMft³/hr)	(lbs/hr)	(tons/yr)
PM (total)[a]	0.0074	7.6	1.631	12.46	24.2
PM-10[a]	0.0074	7.6	1.631	12.46	24.2
PM-2.5[a]	0.0074	7.6	1.631	12.46	24.2
SO2[a]	0.00087	0.9	1.631	1.40	2.7
CO[a]	0.06	62.0	1.631	101.04	196.1
NOx[a]	0.15	154.9	1.631	252.60	490.2
VOC[a]	0.004	4.1	1.631	6.74	13.1
H2SO4[b]	0.0000166	1.7E-02	1.631	0.03	0.1
Fluorides[c]	negligible	--	1.631	--	--
Pb[d]	4.84E-07	5.0E-04	1.631	8.15E-04	1.6E-03
Grnhse (CO2)	116.2	119,999.7	1.631	195,680.60	379,780.39
Grnhse (CH4)	0.0022	2.3	1.631	3.70	7.2
Grnhse (N2O)	0.0006	0.6	1.631	1.01	2.0
Grnhse (CO2e)	116.44	120,247.6	1.631	196,084.96	380,564.73

Notes:

a - Emission factor taken from facility application, based on vendor estimate (uncontrolled).

b - Assumed to be 2% of SO2 (footnote b in table 1.4-3 of AP-42)

c - No factor in AP-42, Chapter 1.4 (7/98).

d - table 1.4-2 of AP-42

e - Global warming potential (GWP) factor taken from EPA *PSD and Title V Permitting Guidance for Greenhouse Gases* (3/2011). Also listed in facility application.

f - Emissions in bold are included as permit limits.

Sample Calculation - PM-10

0.0074 lb/MMBtu * 1032.7 MMBtu/MMcf * 1.631 MMcf/hr =	12.46	lb/hr

Annual Emissions - Unit 003 and 004 Emissions

Pollutant	Boiler Unit 4 (1684 MMBtu/hr) @ max allowable (3,881.6 hrs)			Boiler Unit 3 (920 MMBtu/hr) @ max allowable (7105 hrs)			Annual Emissions[f]
	Fuel Consumption	Emissions[f]		Fuel Consumption	Emissions[f]		
	(MMCF/hr)	(lbs/hr)	(tons/yr)	MMCF/hr	(lbs/hr)	(tons/yr)	(tons/yr)
PM (total)[a]	1.631	**12.46**	24.19	0.891	**5.81**	24.19	**24.2**
PM-10[b]	1.631	**12.46**	24.19	0.891	**5.81**	24.19	**24.2**
PM-2.5[b]	1.631	**12.46**	24.19	0.891	**5.81**	24.19	**24.2**
SO2[a]	1.631	**1.40**	2.71	0.891	0.76	2.71	**2.7**
CO[a]	1.631	**101.04**	196.10	0.891	55.20	196.10	**196.1**
NOx[d] (Unit 4)	1.631	**252.60**	490.25	--	--	--	**522.9**
NOx[d] (Unit 3)	--	--	--	0.891	147.20	522.93	
VOC[a]	1.631	6.74	13.07	0.891	3.68	13.07	13.1

Notes:

a - Emission factor taken from facility application, based on vendor estimate (uncontrolled).

b - Assumed to be 2% of SO2 (footnote b in table 1.1-3 of AP-42)

c - No factor in AP-42, Chapter 1.4 (7/98).

d - table 1.4-2 of AP-42

e - Global warming potential factor taken from EPA *PSD and Title V Permitting Guidance for Greenhouse Gases* (3/2011).

f - Emissions in bold are included as permit limits.

Attachment A-3 to Dominion - Bremo Facility Fuel Modification Calculations
PSD (Art. 8) Emission Increases/Decreases

Source: Dominion - Bremo (Facility Fuel Modification Project), CEDS #19
Registration Number: 40199

PSD (Article 8) Applicability

			Future Emissions After Conversion					
	Selected Baseline, tpy (2009-2010)	Unit 3 and 4 Boiler Emission Rate (lb/MMBtu)	Units 3 & 4 Combined (TPY)	Aux Boiler and Pipeline Heater (tpy)	Total (tpy)	Net Change in Emissions (tpy)	PSD Significant Emissions Threshold (tpy)	PSD Signifcant Change? (Yes or No)
PM (total)	406.91	0.0074	24.2	1.3	25.5	-381.44	25	NO
PM-10	406.99	0.0074	24.2	1.3	25.5	-381.52	15	NO
PM-2.5	29.66	0.0074	24.2	1.3	25.5	-4.19	10	NO
SO2	7355.63	0.0083	2.7	1.1E-01	2.8	-7352.81	40	NO
CO	103.9	0.16/0.15	196.10	4.7	200.8	97.0	100	NO
NOx	1955.8	0.06	522.9	4.3	527.2	-1428.65	40	NO
VOC	12.4	0.004	13.1	6.4E-01	13.7	1.29	40	NO
H2SO4	147.1	1.70E-05	0.054	2.18E-03	5.6E-02	-147.04	7	NO
Fluorides	31.0	Neg.	--	--	--	-30.95	3	NO
Pb	0.04	4.84E-07	0.002	6.2E-05	--	-0.03	0.6	NO
GHGs (Mass)	1,524,987.7	116.2	379,789	14,901.1	394,690.5	-1130297.10	NA	NA
Grnhse (CO2)	1,524,973.2	116.2	379,780	14,901	394,681	-1130292.16	NA	NA
Grnhse (CH4)	8.3	0.0022	7.2	2.8.E-01	7.5	-0.78	NA	NA
Grnhse (N2O)	6.2	0.00006	2.0	7.7.E-02	2.0	-4.16	NA	NA
Grnhse (CO2e)	1,527,068.5	116.44	380,565	14,930	395,495	-1131573.24	75,000	NA

= scheduled to change w/ updated application (March 2013).

Source: Dominion - Bremo (Facility Fuel Modification Project), CEDS #19
Registration Number: 40199

Modeling Increase = FPTE - CPTE

Modeling Increases

	Kewanee Aux. Boiler[1]	turbine[2]	Boiler[3]	Boiler[3]	coal handling[4]	CPTE(tpy)	Future PTE(tpy)	Delta (FPTE-CPTE), tpy
	001	002	003	004	ES-5			
PM (total)	22.86	8.76	562.87	1050.98	4.8	1,650.3	25.5	-1,624.8
PM-10	22.86	8.76	562.87	1050.98	2.1	1,647.6	25.5	-1,622.1
PM-2.5	22.86	-	562.87	1050.98	--	1,636.7	25.5	-1,611.3
SO2	100.52	-	10545.64	19645.88	--	30,292.0	2.8	-30,289.2
CO	0.76	-	79.89	148.83	--	229.5	200.8	-28.6
NOx	17.51	-	1837.50	3423.15	-	5,278.2	527.2	-4,751.0
VOC	0.09	-	9.59	17.86	--	27.5	13.7	-13.8

[1] - Emission limits for Auxuillary Boiler (PM and SO2) from facility's TV permit, dated 1/1/08. Permit lists limits in lb/hr. Hourly limits multipiled by 8760 hours. Limits for other crtieria pollutants determined using AP-42 emission factors, Section 1.1-4, for coal combustion.

[2] - Emission limits for turbine from facility's TV permit, dated 1/1/08. Permit lists limits in lb/hr. Hourly limits multiplied by 8760 hours. Limits not determined for other pollutants since turbine will remain unchanged.

[3] - Emission limits for Boilers 003 and 004 (PM, SO2 and NOx) from facility's TV permit, dated 1/1/08. Permit lists limits in lb/hr. Hourly limits multiplied by 8760 hours. NOx concentraion limits converted to lb/hr.

[4] - per NSR permit dated, 2/22/06.

Greenhouse Gas Emissions

Source: Dominion - Bremo (Facility Fuel Modification Project), CEDS #19
Registration Number: 40190
CO2 and CO2e Calculations

Natural Gas - Potential to Emit

Heat Input:	1684	MMBtu/hr (Unit 4)
	6536666.667	MMBtu/yr (Unit 4); (1684 MMBtu/hr * 3874.3 hrs/yr)
Heat Content:	1032.7	BTU/ft³ (per facility application, 11/26/12)
Fuel Consumption:	1630.68	Mft³/hr
	1.631	MMft³/hr (@ max hrs = 3874.3 hrs/yr)
	6329.69	MMft3/yr
Operational Hours	3881.6	

Heat Input:	920	MMBtu/hr (Unit 3)
	13800	MMBtu/yr (Unit 3); (920 MMBtu/hr * 15 hrs/yr)
Heat Content:	1032.7	BTU/ft³ (per facility application, 11/26/12)
Fuel Consumption:	890.869	Mft³/hr
	0.8909	MMft³/hr
	13.36	MMft3/yr
Operational Hours	15	

Heat Input:	25	MMBtu/hr (Exempt from permitting)
	219000	MMBtu/yr
Heat Content:	1032.7	BTU/ft³ (per facility application, 11/26/12)
Fuel Consumption:	24.21	Mft³/hr
	0.024	MMft³/hr
	212	MMft³/yr
Operational Hours	8760	

Heat Input:	4.277	MMBtu/hr (Exempt from permitting)
	37466.52	MMBtu/yr
Heat Content:	1032.7	BTU/ft³ (per facility application, 11/26/12)
Fuel Consumption:	4.14	Mft³/hr
	0.004	MMft³/hr
	36	MMft³/yr
Max operational hrs	8760	hours

Pollutant	Emission Factor	Individual Units (Pounds)					Global Warming Potential Factor	CO_2 Equivalent (CO_{2e}) Emissions
		Emissions - B4	Emissions- B3	Emissions- Aux Blr	Emissions - Pipeline Htr	Mass Basis Emissions		
	(lb/MMBtu)	(lb/yr)	(lb/yr)	(lb/Yr)	(lb/yr)	(tpy)		(tpy)
CO_2 [a]	116.20	759,560,666.667	1,603,560.000	25,447,800.000	4,353,609.624	395,482.82	1	395,482.82
Methane [a]	0.0022	14,380.667	30.360	481.800	82.426	7.49	21	157.24
N_2O [a, b]	0.0006	3,922.000	8.280	131.400	22.480	2.04	310	633.04
Total (Mass)	--	--	--	--	--	395,492.35	--	--
Total (CO_{2e})	--	--	--	--	--	--	--	396,273

Pollutant	Emission Factor	Individual Units (tons)					Global Warming Potential Factor	CO_2 Equivalent (CO_{2e}) Emissions
		Emissions - B4	Emissions- B3	Emissions- Aux Blr	Emissions - Pipeline Htr	Mass Basis Emissions		
	(lb/MMBtu)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)		(tpy)
CO_2 [a]	116.20	379,780.33	801.78	12,723.90	2,176.80	395,482.82	1	395,482.82
Methane [a]	0.0022	7.19	1.52E-02	0.24	0.04	7.49	21	157.24
N_2O [a, b]	0.0006	1.96	4.14E-03	0.07	0.01	2.04	310	633.04
Total (CO_{2e})	116.44	380,539.24	803.38	12,749.33	2,181.15	--	--	396,273.1

Notes:

a - Emission factor taken from AP-42, Chapter 1.4 (7/98).

b - Emission factor assumes use of a low-NOx burner.

c - Global warming potential factor taken from EPA *PSD and Title V Permitting Guidance for Greenhouse Gases* (3/2011).

Attachment A-6
Baseline Actual Emissions

Pollutant	2012	2011	2010	2009	2008
	tons/yr				
PM	374.09	374.35	432.55	381.28	151.44
PM 10	374.21	374.18	432.59	381.39	83.28
PM 2.5	31.63	31.60	31.42	27.89	41.03
SO2	6481.43	6481.43	7741.40	6969.85	8691.31
NO2	1880.40	1880.40	2308.50	1603.18	2819.12
CO	40.09	89.05	108.55	99.21	130.34
VOC	4.76	10.71	12.97	11.88	15.61
PB	0.04	0.04	0.04	0.04	0.04
HCL	93.98	211.87	258.72	236.67	311.92
NH3	0.04	0.10	0.12	0.11	0.15
HF	11.75	26.48	32.34	29.58	38.99
H2SO4	--	--	154.80	139.40	173.80
Fluorides	--	--	32.30	29.60	39.00
CO2	--	--	2078930.00	971016.40	1258917.20
CH4	--	--	8.60	7.90	10.40
N2O	--	--	6.50	5.90	7.80
GHG Mass	--	--	2078945.10	971030.20	1258935.40
GHG CO2e	--	--	2081125.60	973011.30	1261553.60

Pollutant	'12/'11	'11/'10	'10/'09	'09/'08	BAE [a]
	tons/yr				(tons/yr)
PM	374.22	403.45	406.91	266.36	406.91
PM 10	374.20	403.38	406.99	232.34	406.99
PM 2.5	31.62	31.51	29.66	34.46	29.66
SO2	6,481.43	7,111.41	7,355.63	7,830.58	7,355.63
NO2	1,880.40	2,094.45	1,955.84	2,211.15	1,955.84
CO	64.57	98.80	103.88	114.77	103.88
VOC	7.73	11.84	12.42	13.74	12.42
PB	0.04	0.04	0.04	0.04	0.04
HCL	152.93	235.30	247.70	274.30	247.70
NH3	0.07	0.11	0.12	0.13	0.12
HF	19.12	29.41	30.96	34.29	30.96
H2SO4	--	--	147.10	156.60	147.10
Fluorides	--	--	30.95	34.30	30.95
CO2	--	--	1,524,973.20	1,114,966.80	1,524,973.20
CH4	--	--	8.25	9.15	8.25
N2O	--	--	6.20	6.85	6.20
GHG Mass	--	--	1,524,987.65	1,114,982.80	1,524,987.65
GHG CO2e	--	--	1,527,068.45	1,117,282.45	1,527,068.45

a - Baseline Actual Emissions (BAE) are within the five-year period immediately preceding when the owner begins actual construction of the project. Construction of the project is scheduled for December 2013, therefore the BAE are calculated using emissions data from the 12-month calendar years 2009 and 2010.

Attachment B

Correspondence Regarding Brown Plume Emissions

Medlin, Debbie (DEQ)

From: William A Scarpinato [william.a.scarpinato@dom.com]
Sent: Tuesday, November 27, 2012 8:31 AM
To: Medlin, Debbie (DEQ)
Subject: Document that you requested
Attachments: The Role of carbon Monoxide in NO2 Plume Formation.pdf.pdf

Deb,

Hope you had a great Thanksgiving, we had a house full and are still eating Turkey at my place. Here is the document that you requested, sorry it took me so long to get it to you, with the Holiday last week I got behind. You should have our updated application we sent it out on the 20th, let me know if you have any questions on that.

Regards,
Bill Scarpinato, Jr.
Environmental Consultant - Air
Dominion Resources Services, Inc. – Environmental Business Support
O:* *(804) 273-3019
C:* *(804) 461-1426 (Please note new cell number)
5000 Dominion Blvd, Glen Allen, VA 23060
William.A.Scarpinato@dom.com

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The Role of Carbon Monoxide in NO_2 Plume Formation

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GE Corporate Research and Development,
One Research Circle,
Niskayuna, NY 12309

Through a series of computational studies, carbon monoxide has been identified as an important promoter of NO oxidation to NO_2 in combustion turbine exhaust gas at intermediate temperatures (450 to 750°C). NO_2 formation is accompanied by enhanced CO burnout at these temperatures. Perfectly stirred reactor and plug flow reactor calculations indicate that concentrations of CO as low as 50 ppmv in exhaust gas containing 25 ppmv NO can result in the conversion of 50 percent of the NO to NO_2 in less than 1 s. NO_2 concentrations as low as 15 ppmv can result in visible, yellow-brown plumes from large diameter exhaust stacks. If NO_2 plumes are to be prevented, then designers of gas turbines and heat recovery steam generators need to be aware of the relationships between time, temperature, and composition which cause NO_2 to form in exhaust gas. Reaction path analysis indicates that the mutually promoted oxidation of CO and NO occurs through a self-propagating, three-step chain reaction mechanism. CO is oxidized by OH ($CO+OH \rightarrow CO_2+H$), while NO is oxidized by HO_2: $NO+HO_2 \rightarrow NO_2+OH$. In a narrow temperature range, the H-atom produced by the first reaction can react with O_2 in a three body reaction to yield the hydroperoxy radical needed in the second reaction: $H+O_2+M \rightarrow HO_2+M$, where M is any third body. The observed net reaction is $CO+O_2+NO \rightarrow CO_2+NO_2$, which occurs stoichiometrically at temperatures below about 550°C. As the temperature increases, additional reaction pathways become available for H, HO_2, and OH which remove these radicals from the chain and eventually completely decouple the oxidation of CO from NO. An abbreviated set of elementary chemical reactions, including 15 species and 33 reactions, has been developed to model CO-enhanced oxidation of NO to NO_2. This reaction set was derived from a larger reaction set with more than 50 species and 230 elementary chemical reactions, and was validated by comparison of PSR and PFR calculations using the two sets.
[S0742-4795(00)01402-2]

Introduction

The fractional distribution of NO_x between NO and NO_2 in the exhaust from combustion systems is of considerable importance. The toxicity of NO_2 is greater than the toxicity of NO, and some localities have regulated the color and/or opacity of exhaust gas plumes (NO is colorless, while NO_2 is red-brown in color). NO_2 can be found in the exhaust from boilers, reciprocating engines, and combustion turbine engines. However, NO_2 is generally not produced in significant quantities within combustors themselves. The principal in-combustor formation mechanism is the mixing of hot gases containing NO with cooling or dilution air in the latter portion of the combustor, leading to the production of HO_2 and then NO_2 via $NO+HO_2=NO_2+OH$ [1]. The resulting NO_2 formed is usually a small fraction (less than 5 percent) of the total NO_x present. Furthermore, this pathway is physically removed in lean premixed gas turbine combustion systems because there is no wall (or "liner") film cooling and there is no dilution jet air. Measurements made in the bottoming cycle equipment downstream of these gas turbines tend to confirm the hypothesis that there is initially little or no NO_2 present in the gas turbine exhaust, but a large fraction (more than 50 percent) of the NO may be oxidized to NO_2 as the gas is cooled from the gas turbine exhaust temperature (about 600°C) to the stack exit temperature, resulting in visible NO_2 plumes [2]. At typical stack diameters, NO_2 should become visible at a concentration of about 10–15 ppmv.

One potential pathway identified in the literature is the reaction of unburned fuel with flame-generated NO downstream of the combustor. Previous experimental and theoretical studies [3–6] have shown that low concentrations (1 to 1000 ppm) of fuels can be strong promoters of NO oxidation to NO_2 at intermediate temperatures (300 to 700°C). Hydrocarbons vary in their effectiveness in promoting NO oxidation to NO_2, with C_3 and C_4 species generally being more effective than C_1 and C_2 species and H_2. CO has been reported to be relatively ineffective at promoting NO oxidation [6].

However, observations from gas turbine power plants equipped with lean premixed combustion systems suggest that installations operating at part load with high CO emissions (~50 ppmv) can have visible yellow-brown exhaust plumes, even when total NO_x is relatively low (~25 ppmv) and significant quantities of unburned hydrocarbons are not found. Since the unburned fuel pathway to NO_2 can be ruled out in these cases, the question of the importance of CO in converting NO to NO_2 is reopened.

Glarborg et al. [7] recently completed an experimental and theoretical study of interactions between CO, NO, NO_2, and H_2O in a flow reactor. They concluded that the presence of NO may enhance or inhibit CO oxidation, depending upon the exact temperature and composition of the exhaust gas mixture. However, their experimental test conditions were somewhat different from the conditions expected in turbine exhaust. For example, their CO concentrations (450 to 1600 ppm) were much higher than typically found in turbine exhaust, and their O_2 concentrations (2.0 to 4.3 percent) were lower than usually found.

The purpose of the present computational study was to extend the analysis of Glarborg et al. to more closely match the conditions found in gas turbine exhaust, with the overall objective of gaining a better understanding of the role of CO in the oxidation of NO to NO_2 at intermediate temperatures (400 to 850°C). Perfectly stirred reactor (PSR) and plug flow reactor (PFR) calcula-

Contributed by the International Gas Turbine Institute (IGTI) of THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS for publication in the ASME JOURNAL OF ENGINEERING FOR GAS TURBINES AND POWER. Paper presented at the International Gas Turbine and Aeroengine Congress and Exhibition, Indianapolis, IN, June 7–10, 1999; ASME Paper 99-GT-53. Manuscript received by IGTI March 9, 1999; final revision received by the ASME Headquarters January 3, 2000. Associate Technical Editor: D. Wisler.

tions, as well as a reaction path analysis, were completed with both Miller and Bowman's [8] detailed chemical reaction set (more than 50 species and 230 elementary reactions) and a reduced reaction set (15 species and 33 elementary reactions) derived from their work. Predictions from both reaction sets were also compared to calculations using the reaction set proposed by Glarborg et al. [7,9] (54 elementary reactions) and the reaction set developed by Bowman et al. [10] for the Gas Research Institute (277 elementary reactions). Comparisons of the predictions of the four different reaction sets served to validate the reduced reaction set presented here. PFR calculations were performed because the cooling of turbine exhaust gas in a heat recovery steam generator (HRSG) is, to a first approximation, a plug flow process. The PSR calculations served as a convenient, second test case for comparing the complete reaction set with the reduced reaction set.

There have been reports (e.g., [11]) of brown NO_2 plumes forming far downstream (0.5–5.0 km) of power plant exhaust stacks. These NO_2 plumes result from reactions between NO in the exhaust and ambient ozone (O_3). The mechanism described in this paper explains the visible NO_2 plumes sometimes observed at the immediate exit (0–1 m) of an exhaust stack.

PSR and PFR Calculations

The initial gas composition used for all PSR and PFR calculations was determined by assuming complete combustion of methane in air (21 percent O_2, 79 percent N_2) at a particular equivalence ratio (φ). CO and NO were then added to the mixture at the desired concentrations. Unless otherwise indicated, the only species present in the initial mixture were O_2, N_2, CO_2, and H_2O, as well as any added CO and NO.

PSR and PFR calculations were completed on a VAX 7610 computer using the Chemkin II package of subroutines and associated programs [12,9,13]. The Chemkin software allowed adjustment of absolute and relative tolerances to insure computed mole fractions contained roughly four significant digits, even for species with concentrations as low as 10^{-6} ppm. For calculations at $P=1$ atm, four different reaction sets were used: (1) the well-known reaction set of Miller and Bowman [8]; (2) a reduced, 33-step reaction set derived from Miller and Bowman's work (see Table 1); (3) the reaction set developed by Glarborg et al. [7]; and (4) the most recent version of the Gas Research Institute reaction set, GRI-Mech 2.11 (Bowman et al.). For calculations at elevated pressures, the modifications recommended by Michaud et al. [14] were added to the Miller and Bowman reaction set. The reaction path analysis aided in the selection of the key reactions to be retained in the reduced reaction set in Table 1. This reduced set consists of reactions 61-64, 130-139, 143, 145-150, 166, 188-191, 204-207, and 232-234 in Appendix A of Miller and Bowman [8].

Results

The results from typical constant temperature and pressure PSR calculations are shown in Figs. 1 and 2. The inlet composition for the PSR calculations shown in Figs. 1 and 2 is burned gas resulting from complete combustion of methane in air at $\varphi=0.5$ (5 percent CO_2, 10 percent H_2O, 10 percent O_2, 75 percent N_2) with 50 ppmv of CO and either 25 ppmv (solid lines and symbols) or 0 ppmv (dashed lines) of NO added. PSR pressure was set to $P=1$ atm and the residence time was 0.5 s. For these conditions the fractional conversion of NO to NO_2 peaks at about 650°C, with about 30 percent of the NO converting into NO_2 and total NO_x remaining constant. CO decreases monotonically as temperature increases.

The solid and dashed lines in Figs. 1 and 2 indicate results using the Miller and Bowman (MB) reaction set. Symbols represent calculations with either the reduced reaction set in Table 1 (■), the 1995 Glarborg et al. (G et al.) reaction set (●), or the GRI-Mech 2.11 reaction set (▲). Figures 1 and 2 show that calculations with the reduced reaction set in Table 1 are indistinguishable from calculations with the complete MB reaction set. In addition, the four different reaction sets are in excellent qualitative agreement for all species and very good quantitative agreement for most species. Differences between reaction sets are largest for HO_2, with a maximum difference of about a factor of 3 at high temperatures. Notice, however, that the differences between reaction sets are much smaller for the important species of interest: CO, NO, and NO_2.

With the inlet NO concentration set to 0 ppmv (the dashed lines in Figs. 1 and 2), CO oxidation is greatly suppressed at low temperatures, but is almost unaffected at temperatures above 850°C. At low temperatures, the presence of 25 ppm NO in the inlet gas increases the OH concentration by almost a factor of 1000. NO has a similar effect on H atom concentrations, while HO_2 concentrations are only slightly affected by the presence of NO in the inlet gas. At high temperatures, the presence of NO in the inlet gas has no effect on these radical species concentrations.

A reaction path analysis provides useful insight into the chemical mechanisms causing the effects observed in Figs. 1 and 2. Under all conditions, the primary pathway for CO oxidation is reaction *R*2 in Table 1:

$$CO+OH\rightarrow CO_2+H, \qquad (R2)$$

and the primary pathway for NO oxidation is

$$NO+HO_2\rightarrow NO_2+OH. \qquad (R23)$$

However, key differences are observed in the reaction pathways for radical species. At low temperatures (450–650°C), when NO is present in the inlet, almost all of the H atom is destroyed through

$$H+O_2+M\rightarrow HO_2+M. \qquad (R9)$$

Under these conditions *R*2, *R*23, and *R*9 form a self-sustaining set of chain reactions. The sum of the three reactions is the overall reaction

$$CO+NO+O_2\rightarrow NO_2+CO_2$$

with no net consumption of radical species. The key chain initiation step is not thermal dissociation of stable species, but rather the slow reaction

$$CO+O_2\rightarrow CO_2+O. \qquad (R3)$$

O atom produced through *R*3 then participates in an important chain branching reaction,

$$H_2O+O\rightarrow 2OH, \qquad (-R13)$$

which produces the OH needed for *R*2, thus initiating the three-step chain reaction. Reactions *R*2, *R*23, and *R*9 then propagate the chain reaction, and proceed to oxidize NO and CO, with no net consumption of radicals. At temperatures below 550°C, almost every mole of CO oxidized to CO_2 also results in one mole of NO oxidized to NO_2.

At very low temperatures (below 450°C), *R*3 is too slow to provide sufficient quantities of O atom for the chain reactions to proceed at a significant rate. At high temperatures (above 650°C), *R*3 and the reverse direction of *R*13 are still the key chain initiation and chain branching reactions. However, additional reaction pathways become available for H, HO_2, and OH. These reactions remove radicals from the chain and decouple the oxidation of CO from NO. For example, as temperature increases, *R*9 becomes a less important pathway for H atom destruction as the alternate $H+O_2$ pathway

$$H+O_2\rightarrow OH+O \qquad (-R7)$$

becomes more important. At 850°C, about 50 percent of the H atom destruction occurs through *R*9, the remainder being destroyed through the reverse direction of *R*7. In addition, only 20 percent of the HO_2 that is consumed results in oxidation of NO to NO_2 through *R*23 (versus almost 100 percent at 500°C). The remainder of the HO_2 is being destroyed through

Table 1 Rate parameters for 33-step reduced reaction set

	REACTION	Forward rate parameters A	b	E
1.	$CO + O + M = CO_2 + M$	6.17×10^{14}	0.00	3000.
2.	$CO + OH = CO_2 + H$	1.51×10^{07}	1.30	−758.
3.	$CO + O_2 = CO_2 + O$	1.60×10^{13}	0.00	41000.
4.	$HO_2 + CO = CO_2 + OH$	5.80×10^{13}	0.00	22934.
5.	$H_2 + O_2 = 2\,OH$	1.70×10^{13}	0.00	47780.
6.	$H + H_2 = H_2O + H$	1.17×10^{09}	1.30	3626.
7.	$O + OH = O_2 + H$	4.00×10^{14}	−0.50	0.
8.	$O + H_2 = OH + H$	5.06×10^{04}	2.67	6290.
9.	$H + O_2 + M = HO_2 + M$	3.61×10^{17}	−0.72	0.
	Enhanced third-body efficiencies: $H_2O = 18.6$, $CO_2 = 4.2$, $H_2 = 2.9$, $CO = 2.1$, $N_2 = 1.3$			
10.	$OH + HO_2 = H_2O + O_2$	7.50×10^{12}	0.00	0.
11.	$H + HO_2 = 2\,OH$	1.40×10^{14}	0.00	1073.
12.	$O + HO_2 = O_2 + OH$	1.40×10^{13}	0.00	1073.
13.	$2\,OH = O + H_2O$	6.00×10^{08}	1.30	0.
14.	$H + H + M = H_2 + M$	1.00×10^{18}	−1.00	0.
	Enhanced third-body efficiencies: $H_2 = 0.0$, $H_2O = 0.0$, $CO_2 = 0.0$			
15.	$H + OH + M = H_2O + M$	1.60×10^{22}	−2.00	0.
	Enhanced third-body efficiencies: $H_2O = 5.0$			
16.	$O + O + M = O_2 + M$	1.89×10^{13}	0.00	−1788.
17.	$H + HO_2 = H_2 + O_2$	1.25×10^{13}	0.00	0.
18.	$2\,HO_2 = H_2O_2 + O_2$	2.00×10^{12}	0.00	0.
19.	$H_2O_2 + M = 2\,OH + M$	1.30×10^{17}	0.00	45500.
20.	$H_2O_2 + H = HO_2 + H_2$	1.60×10^{12}	0.00	3800.
21.	$H_2O_2 + OH = H_2O + H$	1.00×10^{13}	0.00	1800.
22.	$CO_2 + N = NO + CO$	1.90×10^{11}	0.00	3400.
23.	$HO_2 + NO = NO_2 + OH$	2.11×10^{12}	0.00	−479.
24.	$NO_2 + H = NO + OH$	3.50×10^{14}	0.00	1500.
25.	$NO_2 + O = NO + O_2$	1.00×10^{13}	0.00	600.
26.	$NO_2 + M = NO + O + M$	1.10×10^{16}	0.00	66000.
27.	$N_2O + H = N_2 + OH$	7.60×10^{13}	0.00	15200.
28.	$N_2O + M = N_2 + O + M$	1.60×10^{14}	0.00	51600.
29.	$N_2O + O = N_2 + O$	1.00×10^{14}	0.00	28200.
30.	$N_2O + O = 2\,NO$	1.00×10^{14}	0.00	28200.
31.	$N + NO = N_2 + O$	3.27×10^{12}	0.30	0.
32.	$N + O_2 = NO + O$	6.40×10^{09}	1.00	6280.
33.	$N + OH = NO + H$	3.80×10^{13}	0.00	0.

Note: forward rate coefficients (k_f) are of the form $k_f = A\,T^b \exp(-E/_{RT})$, where the dimensions of A are mole-cm-sec-K, the units of E are cal/mole, T is absolute temperature, and R is the ideal gas constant.

$$HO_2 + OH \rightarrow H_2O + O_2. \quad (R10)$$

NO_2 production reaches a maximum and then slows down as temperature increases, and CO oxidation increases monotonically with temperature, because as temperature increases (i) $R10$ consumes HO_2 that would have produced NO_2 at lower temperatures through $R23$, and (ii) the reverse direction of $R7$ produces the OH needed for CO oxidation that $R23$ produced at lower temperatures.

If NO is not present at low temperatures, CO oxidation slows considerably, as shown in Fig. 1. $R3$ and the reverse direction of $R13$ are still the important chain initiating and chain branching reactions. OH produced through the reverse direction of $R13$ still oxidizes CO, and the H from $R2$ reacts through $R9$ to form HO_2. However, without NO to convert HO_2 back to OH through $R23$, OH concentrations remain depressed (see Fig. 2) and CO oxidation slows down. At higher temperatures, new sources of OH become available (primarily through the reverse direction of $R7$), allowing CO oxidation to proceed without NO.

The results from typical constant temperature and pressure PFR calculations using the Miller and Bowman [8] reaction set are shown in Figs. 3 and 4. The initial condition for the calculations shown in Figs. 3 and 4 is again burned gas resulting from complete combustion of methane in air at $\varphi = 0.5$ (5 percent CO_2, 10 percent H_2O, 10 percent O_2, 75 percent N_2) at $P = 1$ atm, $T = 600°C$, with 50 ppmv CO added, and either 25 or 0 ppmv NO. For all of the species shown, the curves produced using the reduced reaction set in Table 1 are indistinguishable from the curves produced using the full MB reaction set, and so have not been shown. Calculations performed using the Glarborg et al. [7] reaction set and GRI-Mech 2.11 were again in good agreement with the MB and Table 1 reaction sets, but have not been shown for clarity.

When NO is present (the solid lines in Figs. 3 and 4), there is a short induction period (about 0.2 s) during which time radical species build up to relatively high concentrations. The end of the induction period is marked by the onset of a period of relatively

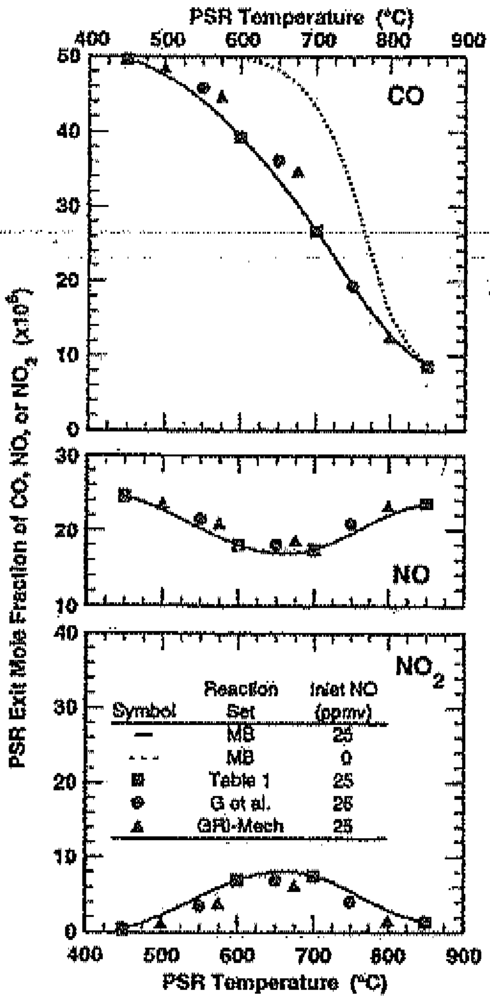

Fig. 1 Calculated concentrations of CO (top), NO (middle) and NO_2 (bottom) in constant pressure (P=1 atm) perfectly stirred reactors (PSRs) at various temperatures. Inlet gas composition—75 percent N_2, 10 percent O_2, 10 percent H_2O, 5 percent CO_2, 50 ppmv CO, and either 25 ppmv NO (solid lines and symbols) or 0 ppmv NO (dashed line). Solid and dashed lines indicate calculations using the Miller and Bowman reaction set. Symbols are points calculated using the reaction set in Table 1 (■), Glarborg et al (●), or GRI-Mech 2.11 (▲).

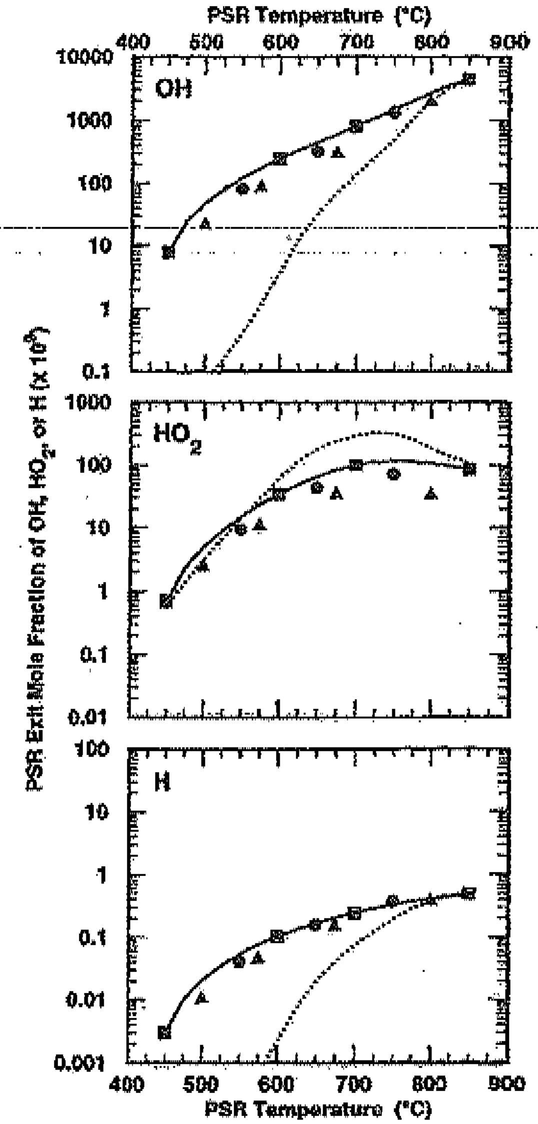

Fig. 2 Calculated concentrations of OH (top), HO_2 (middle), and H (bottom) at the same conditions as shown in Fig. 1

rapid CO and NO oxidation and a gradual decrease in radical species concentrations. In this particular case, approximately 0.6 moles of NO are oxidized to NO_2 for every mole of CO oxidized to CO_2. After about 1 s, 50 percent of the NO has been oxidized to NO_2. When NO is not present (the dashed lines in Figs. 3 and 4), the chemistry of the PFR is quite different. Concentrations of H, OH, and O are initially suppressed, while HO_2 concentrations increase by nearly a factor of 10. Without NO, overall CO burnout is reduced by a factor of 2. Additional calculations (not shown in Figs. 3 and 4) indicate that if CO is not present, NO oxidation does not occur under these conditions.

A careful examination of Figs. 1–4 reveals that both with and without NO, the composition of the PFR at 0.5 s is very similar to a 0.5 s residence time PSR operating at the same temperature. This similarity arises because (1) the reactions in the PSR and the PFR are the same and relatively slow, and (2) total conversion of CO and NO is low at 0.5 s.

Discussion

At typical gas turbine exhaust temperatures, NO is rapidly oxidized to NO_2 if CO is present. This observation has substantial consequences for the design of downstream process equipment, including HRSG's in bottoming cycles. The gas residence time in a typical HRSG is approximately 2 s, which is more than sufficient time to produce 10–15 ppmv of NO_2 if gas cooling is slow (see Fig. 5). Under part load conditions, when CO is relatively high, rapid quenching of turbine exhaust gas may be needed to prevent the formation of visible NO_2 plumes.

Because the net rate of NO oxidation to NO_2 in exhaust gas is of considerable importance to the designers of boilers (and other downstream process equipment) trying to minimize NO_2 formation, Fig. 5 has been prepared. Figure 5 is intended as an engineering tool that provides quick estimates of maximum NO_2 formation rates (due to only CO-enhanced oxidation) in exhaust gas as a function of temperature, pressure, and initial CO:NO mole ratio. Figure 5 is not intended to be a substitute for more detailed model calculations. The net rates of NO_2 production shown in Fig.

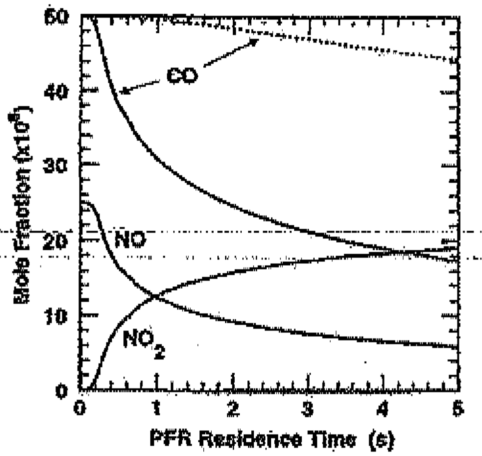

Fig. 3 Calculated composition profiles in a constant temperature (600°C) and pressure (1 atm) PFR. Initial gas composition=75 percent N_2, 10 percent O_2, 10 percent H_2O, 5 percent CO_2, 50 ppmv CO, and either 25 ppmv NO (solid lines, ——) or 0 ppmv NO (dashed line, - - -).

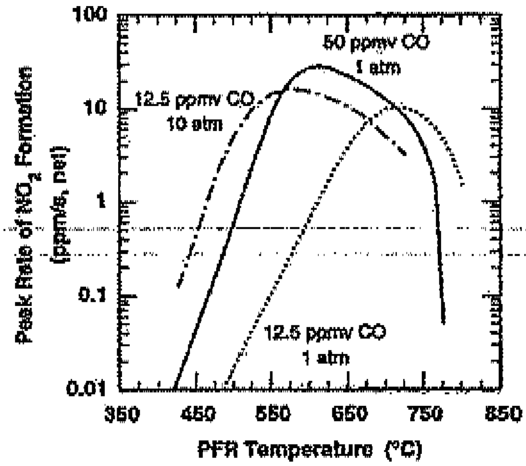

Fig. 5 Peak rates of NO_2 formation in a constant temperature and pressure PFR at various conditions. Initial gas composition=75 percent N_2, 10 percent O_2, 10 percent H_2O, 5 percent CO_2, and 25 ppmv NO. Solid line (——): initial CO concentration=50 ppmv, P=1 atm. Dotted line (···): initial CO concentration=12.5 ppmv, P=1 atm. Dot-dashed line (—·—): initial CO concentration=12.5 ppmv, P=10 atm.

5 are taken from the maximum slope of NO_2 profiles computed in constant temperature and pressure PFR calculations at the indicated conditions. The maximum slope typically occurs immediately after the induction period, typically between 0.2 and 0.4 s (see Fig. 3). NO_2 production rates greater than 10 ppmv per second are possible at temperatures between 575 and 725°C.

The net rate of NO_2 formation shown in Fig. 5 exhibits extremely non-Arrhenius behavior and unusual pressure dependence. At P=1 atm, the rate of NO_2 formation reaches a maximum at temperatures between 600 and 750°C, depending upon the initial CO:NO ratio, and then decreases rapidly as temperature increases. This non-Arrhenius temperature dependence is not surprising, once the competition between $R7$ and $R9$ is recognized as a major factor in joint CO/NO oxidation. Elementary reaction $R9$ is a well known addition/stabilization reaction which has been widely reported to exhibit non-Arrhenius behavior [15]. The non-Arrhenius behavior of $R9$ explains the unusual temperature dependence of NO_2 formation from NO. The slow rate of NO_2 formation at high temperatures also explains why NO_2 is typically not found in exhaust gas immediately exiting a gas turbine. The residence time in the combustor and the turbine is too short (on the order of 25 ms), and the temperature is too high, for significant NO_2 formation to take place.

At temperatures below 550°C, the net rate of NO_2 formation is roughly proportional to P^2. At higher temperatures the pressure dependence becomes more complex as additional reaction pathways become available. At temperatures above 675°C, the net rate of NO_2 production can actually decrease as pressure increases. Again, the unusual pressure dependence of the overall reaction is a direct result of the non-Arrhenius behavior and pressure dependence of $R9$.

The coupling of CO and NO oxidation at low temperatures also has important implications for modeling chemistry in turbulent flow. A typical approach used to include chemistry in turbulent flow models is to determine the flow, temperature, and species concentration fields using only the fuel and air chemistry, and initially neglecting NO_x formation. Once the flow field has been solved, NO_x chemistry is "overlaid" on top of the existing solution, the assumption being that small concentrations of NO_x will not perturb the composition or temperature fields significantly. While NO_x and CO chemistry can be decoupled at high temperatures, this work shows that this assumption is poor at low temperatures. If NO is present, models that decouple CO and NO_x chemistry will under-predict CO burnout at low temperatures (450–750°C).

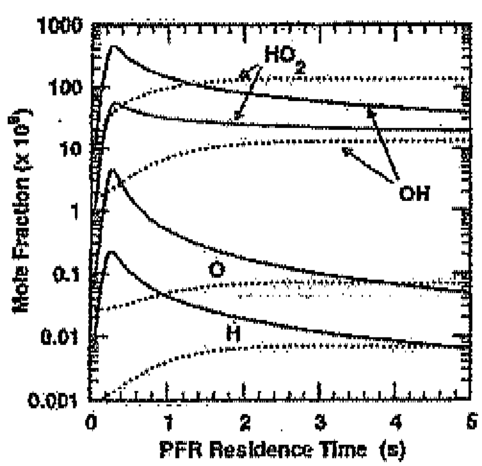

Fig. 4 Calculated PFR composition profiles of important radical species at the conditions of Fig. 3

Conclusions

The yellow-brown plumes sometimes observed in the exhaust from gas turbine power plants are caused by 10–15 ppmv of NO_2. Measurements and prior experience indicate that the NO_2 is not formed in the gas turbine combustor itself. This work has shown that CO plays a critical role in forming NO_2 downstream of the gas turbine. PSR and PFR calculations with four different reaction sets have shown that at temperatures below 800°C, the oxidation reactions of CO and NO are linked together through a chain reaction mechanism. The presence of each enhances the oxidation of the other. Below 550°C, the net reaction stoichiometry of

$$CO+NO+O_2 \rightarrow CO_2+NO_2$$

is expected. CO and NO_x chemistry cannot be decoupled in this temperature regime, and this observation has important implications for designers of boilers and exhaust gas systems trying to minimize NO_2 plume formation.

Acknowledgments

The authors gratefully acknowledge Robert A. Corr, currently with Catalytica, Inc., for introducing them to this problem.

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Medlin, Debbie (DEQ)

From:	William A Scarpinato [william.a.scarpinato@dom.com]
Sent:	Tuesday, November 27, 2012 8:31 AM
To:	Medlin, Debbie (DEQ)
Subject:	Document that you requested
Attachments:	The Role of carbon Monoxide in NO2 Plume Formation.pdf.pdf

Deb,

Hope you had a great Thanksgiving, we had a house full and are still eating Turkey at my place. Here is the document that you requested, sorry it took me so long to get it to you, with the Holiday last week I got behind. You should have our updated application we sent it out on the 20th, let me know if you have any questions on that.

Regards,
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Korean J. Chem. Eng., 28(2), 418-423 (2011)
DOI: 10.1007/s11814-010-0401-6

Catalytic process for decolorizing yellow plume

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(Received 20 July 2010 • accepted 6 August 2010)

Abstract−Yellow-colored exhaust gas streams from internal engines or gas turbines, frequently referred to as "yellow plume," contain nitrogen dioxide (NO_2) at concentrations as low as 15 ppm. The process developed in this work for decolorizing the yellow plume is based on reduction of NO_2 to NO utilizing a combination of a Pt catalyst and a reducing agent. A stoichiometric excess of carbon monoxide, diesel oil, methanol or ethanol were used as reducing agents. Depending on the type of the reductant, the active temperature window of NO_2 reduction was varied with methanol and CO being active at lower temperatures and ethanol and diesel oil at higher temperatures. By changing the Pt loading of the catalysts the active temperature window of NO_2 reduction was also changed, higher loading Pt catalysts being active at lower temperatures. This scheme of NO_2 reduction process was verified in a pilot-scale test with the real exhaust gas from the gas turbine power plant, showing 96% of NO_2 reduction at the stack temperatures of 102-123 °C and at space velocities of 28,000-95,000 h^{-1} with inherent CO in the exhaust gas as the reducing agent.

Key words: Yellow Plume, Decolorizing, NO_2 Reduction, Pt Catalyst, Pilot Scale

INTRODUCTION

Most stationary sources such as boilers, gas turbines and internal engines emit nitrogen oxides. Nitrogen oxides, generally defined as the formula NOx, include NO, NO_2, N_2O_3 and N_2O. Of all the NOx, only NO_2 has a brown color. The exhaust stream containing even 15 ppm of NO_2 may show a yellow color from large diameter stacks [1]. The yellow-colored exhaust stream is frequently referred to as "yellow plume." The NO_2-induced yellow plume causes not only smog, ozone generation (NO_2+O_2+*ultraviolet rays*→NO+O_3) and harmful health effects but also the visible fear of nearby residents. Thus, the sources of the yellow plume are in need of an efficient process which can decolorize the yellow plume to avoid the possible law suits by the residents.

NO_2 formation has been reported to take place through "HO_2 mechanism" as shown below [2]:

$$NO+HO_2 \rightarrow NO_2+OH$$

An unusually high concentration of NO_2 is formed in the areas of large temperature gradients in the flame, the periphery of the flame where the hot combustion gases mix with cool surrounding air. There is a temperature window between 530 °C to 730 °C in which NO to NO_2 conversion occurs readily [3]. The presence of unburned fuel or other oxidizable species such as CO is also known to promote the formation of NO_2 [3].

Three major approaches have been used to reduce NOx emissions: (1) precombustion modifications such as switching fuels and denitrifying the fuel; (2) combustion modification such as changing oxygen concentration and lowering the combustion temperatures; and (3) postcombustion treatment. Considering the cause of formation and the low level of the NO_2 concentration to bring out a yellow color, precombustion and combustion modifications may not be effective in achieving the decolorization of the yellow plume exhaust. The decolorization can be easily achieved by postcombustion treatments since reduction of NOx to the ppm level is frequently practiced by postcombustion treatments.

Since 1960s the method of nonselective catalytic reduction (NSCR) of NOx including NO_2 in the exhaust from nitric acid plants has been applied [4]. Oxygen contained in the exhaust stream is first removed by combusting natural gas or LPG NO and NO_2 in the resultant oxygen deprived stream is reduced to nitrogen with the remaining fuel or with the byproduct from the combustion (CH_4, H_2 and CO, etc) over the catalyst bed. The catalyst is made of 0.3-0.5% Pt and a small amount of Rh on alumina in a honeycomb shape. Depending on the type of the reductant, the operating temperatures are varied: 300-350 °C for H_2 and CO and 500-550 °C for natural gas. A similar process to NSCR is revealed in the U.S. patent [5] with the following procedure. The mixture of NOx containing exhaust stream and fuel passes through an afterburner to remove all the oxygen. After the temperature of the stream is lowered in a heat exchanger, a small amount of air is injected to the oxygen-deprived stream. NO in the resultant stream is oxidized to NO_2 in the first section of the catalyst bed and all NO_2 is reduced to nitrogen with a small amount of excess fuel in the second section of the catalyst bed. The remaining unreacted fuel is oxidized over the final oxidation catalysts. Both NSCR processes and the process are revealed in the U.S. patent [5] are costly processes since they need significant amounts of fuel to consume all the oxygen present in the exhaust stream.

Selective catalytic reduction (SCR) of NOx using ammonia as a reducing agent is considered one of the most effective processes for removing NOx from flue gases [6,7]. The ammonia SCR processes utilizing titania supported vanadia catalysts achieves up to 90% of NOx conversions at temperatures ranging from 200 °C to 400 °C. However, the process suffers from problems of forming

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NH_4HSO_4 causing corrosion and plugging of the reactor and large equipment and operating costs associated with storage, delivery and use of ammonia in the process.

Numerous efforts have been made to replace ammonia with hydrocarbons in SCR processes, especially in an oxygen-rich environment [8-10]. Many types of hydrocarbons have been tested including methane, ethane, ethylene, propane, propylene, octane, benzene, acetone, cyclohexane, diesel oil, methanol, and ethanol. A wide variety of materials show catalytic activity including zeolites [11], ion exchanged zeolites [12] and supported metal catalysts [13]. Most of the efforts have been concentrated on reducing NOx to N_2 at temperatures higher than 200 °C but with limited success. However, the catalytic reduction of NO_2 for the specific purpose of decolorization of the exhaust stream has not been reported.

In addition, a large portion of exhaust stream with a yellow color is vented at temperatures of about 100 °C. For example, the stack gas temperature of a natural gas and/or oil fired combined cycle power plants after the combustion gas passing through a heat recovery steam generator (HRSG) ranges between 100 °C to 150 °C. The exhaust gas temperature from particulate control devices such as electrostatic precipitators or bag filters of coal fired facilities is around 100 °C. No successful result of catalytic reduction of NOx including NO_2 at temperatures of about 100 °C has been reported. If the ammonia SCR process were to be employed in the existing plant for the purpose of removing yellow plume, the gas stream with the right temperature range (200-400 °C) in the process flow has to be pinpointed and to be diverted to go through an SCR reactor. It will require both significant amounts of ductwork and the space for the SCR reactor. An alternative way is to burn additional fuel to raise the stack gas temperature to 200-400 °C, and then to pass the heated gas through the SCR reactor. Heat exchangers can be employed to recover heat from the SCR reactor effluent before venting it to the air. Both options require large capital and operating costs.

The most cost efficient way of decolorizing yellow plume is to utilize a process which operates at exhaust gas temperatures obviating additional heating/cooling devices and the corresponding fuel costs. Additional advantage can be obtained if the process can be operated in oxygen-rich environments with cheaper hydrocarbon type or carbon monoxide reducing agents.

In this work we report a process that can selectively reduce yellow-color-inducing NO_2 in the exhaust gas stream with oxygen present at temperatures close to 100 °C and higher with the combination of Pt catalysts and non-ammonia reducing agents, ensuring an economic way of having colorless exhaust stream vented to the atmosphere.

EXPERIMENTAL

The honeycomb-type Pt impregnated on alumina catalysts was prepared by the incipient wetness method. The ceramic monolith (Corning, Inc.) was dipped into the slurry of porous alumina particles (Aldrich, γ-Al_2O_3, surface area: 170 m^2/g) and then dried several times until the desired amount of alumina was washcoated. Based on the weight of the ceramic honeycomb monolith, about 15 wt% of alumina was washcoated on the monolith. After the calcination of the dried catalyst in air at about 600 °C for 12 hours, the alumina-washcoated monolith was dipped into the aqueous solution of hydrogen hexachloroplatinate (H_2PtCl_6) at 25 °C. The concentration of H_2PtCl_6 was adjusted such that the desired loading of Pt in the final catalyst was obtained. The Pt-containing monolith was dried at 110 °C for 4 hours and recalcined at 500 °C in air (6 hours). The calcined catalyst underwent the hydrogen treatment at the elevated temperature (450 °C, 4 hours) to ensure Pt particles in a reduced metallic form.

The catalysts thus obtained contained 0.001 to 0.33 wt% Pt (based on the total weight of the catalyst including the monolith). The content of Pt in the catalyst was measured by the PIXE (proton induced x-ray emission; manufactured by Korea Institute of Geology and Mineralogy with NEC 5SDH-2 accelerator).

The type of the reducing agent ranged from the inherent gas in the exhaust (CO) to liquid fuels (diesel oil, methanol and ethanol). The amount of reducing agent to be added to the NO_2-containing flue gas was varied in that molar ratio of carbon/NO_2 changed from 2 to 8.

Two different sets of experiments were carried out at different scales of the catalyst volume and the gas flow rate. The first set of experiments was run to screen both the catalyst and the reducing agent in a small-scale unit. The reactor was constructed with a stainless steel tube (inside diameter of 6 cm and length of 14.5 cm). A separate heated inlet for admixing both the liquid reducing agent and water with premixed gas containing NO_2, NO, O_2, CO_2 and N_2 was provided at the position where thorough mixing took place before the mixture contacts the catalyst. Both water and the liquid reductant were supplied by a multiple syringe pump. The catalysts used in the test were 2 cm×2 cm×3 cm size honeycomb type with the cell density of 400 cells per square inch (cpi). The composition of the simulated inlet gas was 120 ppm NO_2, 20 ppm NO, 16% O_2, 2.5% CO_2, 5% H_2O and balance N_2. The typical gas hourly space velocity was 12,500 h^{-1}. The product analysis during the activity measurements was made using an online flue gas analyzer (Green-Line Mk 2, Eurotron).

A larger reactor constructed with a stainless steel tube (inside diameter of 89 cm and length of 123 cm) was used in the proof-of-concept runs (Fig. 1). The real gas turbine exhaust gas showing the yellow color was introduced to the reactor at varying flow rates by

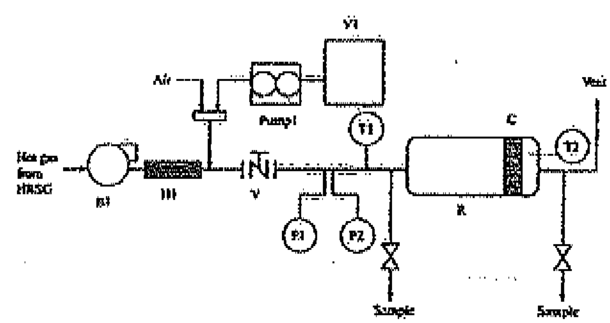

Fig. 1. Schematic diagram of pilot-scale yellow plume decolorization experimental unit (B1: blower, H1: electric heater, V: valve, Pump1: metering pump, V1: methanol storage vessel, T1: thermocouple for inlet temperature measurement, P1, P2: pressure transducers for pitot tube, T2: thermocouple for reactor exit temperature measurement, R: reactor, C: catalyst).

a blower equipped with a valve. Methanol was introduced to the gas stream before the reactor as the reducing agent. When inherent CO was to be used as a reducing agent, no other reducing agent was added to the gas stream. Two different loading of Pt impregnated catalysts were used: 0.22 wt% (200 cpi, 4,500 cm^3) and 0.27 wt% (400 cpi, 9,000 cm^3). The catalyst was placed at the rear end of the reactor. The typical composition of the inlet gas was 24 ppm NO_2, 15 ppm NO, 17% O_2, 2.0% CO_2, 4% H_2O, 360 ppm CO and balance N_2. The temperature of the exhaust gas was about 120 °C, but the electrically heated pipe was used in case of raising the temperature of the gas entering the reactor. The gas hourly space velocity was varied from 28,000 h^{-1} to 95,000 h^{-1}. The flow rate of the exhaust gas was measured by pitot tubes with pressure transducers.

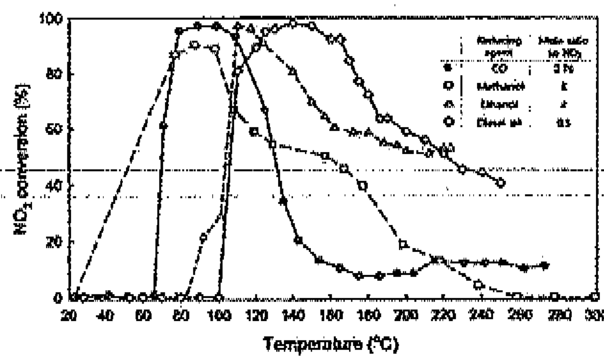

Fig. 3. Change in NO_2 conversion over 0.25 wt% Pt catalyst as a function of reactor inlet temperature when using four different reducing agents (GHSV 12,500 h^{-1}, inlet gas composition: NO_2 120 ppm, NO 20 ppm, O_2 16%, CO_2 2.5%, H_2O 5%, N_2 balance).

RESULTS AND DISCUSSION

1. Yellow Plume Phenomenon

When the exhaust gas contains NO_2, it may show yellow color depending upon both the concentration of NO_2 and the diameter of the stack. Fig. 2 shows pictures of the color of the exhaust gas vented from the stack of a gas turbine-fired power plant in the Republic of Korea during the start-up period. As the power output of the gas turbine was increased from 0 to the steady state output of 80 MW, the yellow color was observed at the output from 10 MW to 50 MW, but the color disappeared at output higher than 60 MW. The gas composition was measured with GreenLine MK2 gas analyzer (Eurotron) during the start-up period and the results are also shown in Fig. 2. As can be seen, the concentration of NO_2 was higher than 30 ppm during the power output between 10 MW and 50 MW, when the yellow color was clearly visible. However, the NO_2 concentration decreased to about 10 ppm at the output higher than 60 MW when the yellow color disappeared. The result in Fig. 2 clearly shows that 30 ppm of NO_2 in the exhaust gas is the main reason for the yellow plume phenomenon (the diameter of the stack was 500 cm).

It should be pointed out that the total NOx concentration of the exit stream from the above gas-fired power plant is below 80 ppm at any stage of the operation, which is far lower than the current limit of Korean regulation (400 ppm). However, the visible yellow plume observed during daily start-up and shutdown periods of the gas-fired power plants irritates nearby residents and causes numerous petitions for corrective actions.

2. Effects of Reducing Agent

The temperature programmed reaction of NO_2 reduction was carried out in a small-scale reactor over the 0.25 wt% Pt impregnated catalyst using different reducing agents, and the results are shown

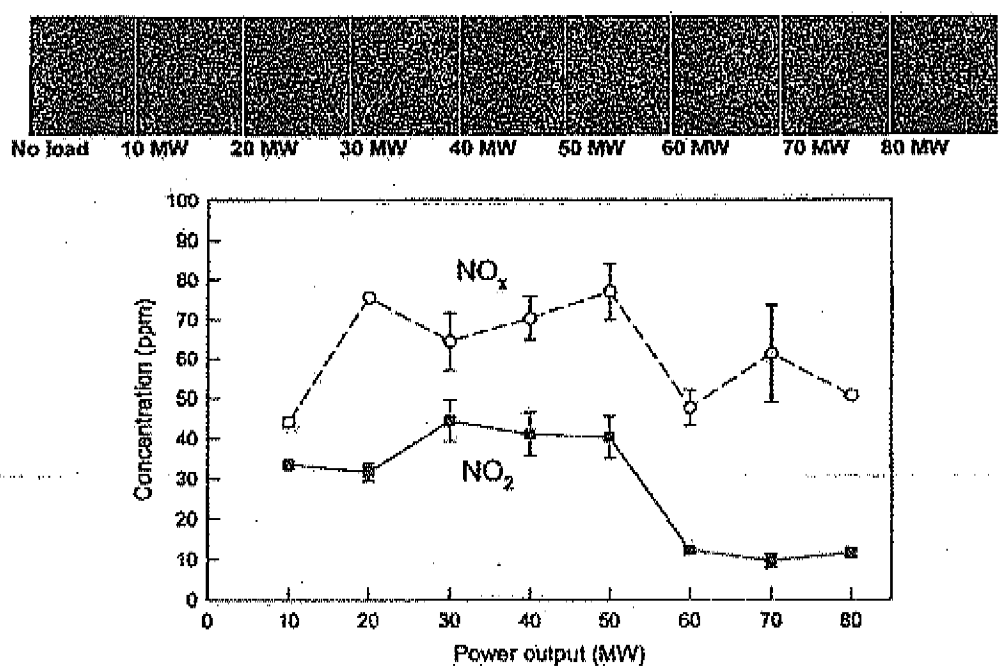

Fig. 2. Change in the color, NO_2 and NOx concentration of exhaust gas from the stack during the start-up period of a gas turbine.

in Fig. 3. The rate of the liquid reducing agent added to the stream was determined in such a way that the mole ratio of carbon atoms in the reductant to NO_2 was 8. For example, diesel oil was regarded as hexadecane and the mole ratio of diesel oil to NO_2 was 0.5. However, in the case of CO, the CO/NO_2 ratio was 2.76.

As can be seen in Fig. 3, more than 90% of NO_2 reduction was obtained at temperatures as low as 70 °C with methanol or CO reductants. When ethanol was used as the reducing agent, the active temperature window for the NO_2 conversion higher than 90% was around 110 °C. In the case of the diesel oil reductant, the active temperature window was even higher (130-170 °C). The results in Fig. 3 indicate that the active temperature window of maximum NO_2 reduction can be varied over the same catalyst by changing the reducing agent. It should be pointed out that NO_2 was converted to NO not to N_2 in all of the runs shown in Fig. 3. In other words, the summation of NO and NO_2 concentration at the outlet of the reactor was the same as the summation of the inlet NOx (NO and NO_2) concentration, indicating that no reduction of NO_2 further than NO was taken place. However, even with reduction of NO_2 only to NO, decolorization of yellow plume can be achieved.

Catalytic reduction of NO in an oxygen-rich environment using the CO reducing agent over Pt catalysts was recently studied. Macleod and Lambert [14] tested the NOx reduction activity of a 0.5 wt% Pt/γ-Al_2O_3 catalyst with 4,000 ppm of CO for the feed gas containing 500 ppm NO and 5% O_2. They reported similar results to ours in that they were not able to observe any NOx reduction below 200 °C but only about the 10% NOx conversion at 250 °C. Instead of NO reduction, NO oxidation to NO_2 started to take place from 230 °C. In a separate experiment, CO was completely oxidized at that temperature and there must have been no reducing agent to prevent NO oxidation to NO_2. They might have observed NO_2 reduction to NO at temperatures lower than 200 °C, if the feed gas contained NO_2.

At those temperatures of the high NO_2 conversion shown in Fig. 3, most of the excess amounts of reducing agents were also oxidized over the same catalyst. Fig. 4 shows the conversion of CO during NO_2 reduction. Although the amount of CO introduced to the gas stream was 2.76 times larger than NO_2 in mole basis, more than 80% of total CO was converted to CO_2 at the high end of the temperature window (100 °C). When the NO_2 conversion started

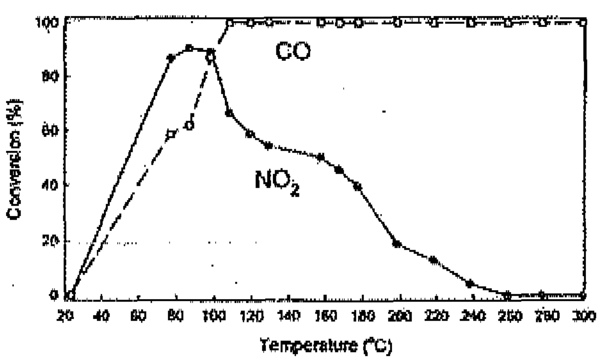

Fig. 4. Change in NO_2 and CO conversion over 0.25 wt% Pt catalyst as a function of reactor inlet temperature (GHSV 12,500 h^{-1}, inlet gas composition: NO_2 120 ppm, NO 20 ppm, O_2 16%, CO_2 2.5%, H_2O 5%, CO 600 ppm, N_2 balance).

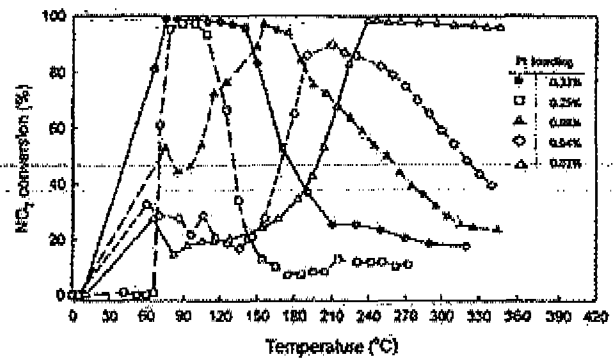

Fig. 5. Change in NO_2 conversion over alumina supported Pt catalysts with different Pt loading as a function of reactor inlet temperature when using methanol reductant (GHSV 12,500 h^{-1}, inlet gas composition: NO_2 120 ppm, NO 20 ppm, O_2 16%, CO_2 2.5%, H_2O 5%, N_2 balance, methanol/NO_2=8).

to decrease, the CO conversion was complete. At those temperatures the normal CO oxidation activity of the Pt catalyst seemed to be higher than the NO_2 reduction activity by CO.

3. Effects of Pt Loading

Five alumina washcoated catalysts with different Pt loading were prepared, and their catalytic activities toward the NO_2 reduction with the methanol reducing agent are shown in Fig. 5. Pt loading was varied between 0.01 wt% and 0.33 wt% based on the total weight of the catalyst including the monolith. As can be seen, the catalyst with higher Pt loading shows the window of high NO_2 reduction at lower temperatures. The catalyst loaded with 0.33 wt% Pt converted more than 95% of NO_2 at temperatures as low as 70 °C. The temperature window of that catalyst for more than 90% of NO_2 conversion spans to 140 °C. However, the temperature window for NO_2 conversion higher than 90% for the catalyst with 0.08 wt% Pt was between 150 and 180 °C. The 0.01 wt% Pt catalyst was active for NO_2 reduction at temperatures higher than 240 °C. Fig. 5 clearly shows that the temperature window for high NO_2 conversion can be varied by changing the catalyst composition, especially the Pt loading.

The above result of changing the active temperature window of NO_2 conversion by using a different composition catalyst has practical importance. The NO_2 decolorization process utilizing the combination of Pt catalysts and the reducing agents above can be applied directly to the exhaust gases discharging at temperatures between 70 °C to 360 °C, making it unnecessary to install additional heating/cooling devices.

Change in the activities of the catalysts with different metal loading is frequently observed when the reaction is structure-sensitive. CO oxidation over supported gold catalysts is a good example. The higher loading catalyst normally contains more metal particles with the larger size [15]. Thus, NO_2 reduction to NO over a Pt catalyst seems to be a structure-sensitive reaction with larger Pt particles being more active at lower temperatures.

4. Effects of Space Velocity

The flow rate of the simulated gas entering the reactor was varied while the temperature was maintained at 100 °C. The methanol injection rate was also changed to make the methanol/NO_2 ratio remain constant at 8. As shown in Fig. 6, the concentration of NOx (NO+

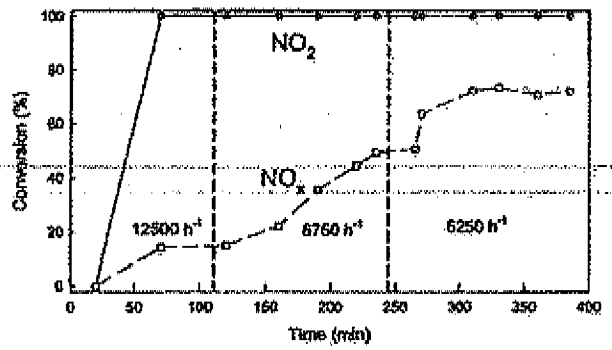

Fig. 6. Change in NO_2 and NOx conversion over 0.33 wt% Pt catalyst at different space velocities (100 °C, inlet gas composition: NO_2 120 ppm, NO 20 ppm, O_2 16%, CO_2 2.5%, H_2O 5%, N_2 balance, methanol/NO_2=8).

NO_2) decreased at the exit of the reactor as the space velocity was lowered, while maintaining the 100% of NO_2 conversion. The result shown in Fig. 6 suggests that the combination of the 0.33 wt% Pt catalyst and the methanol reductant was able to obtain the reduction product of NO_2 other than NO at lower space velocities. Our gas analyzer was not equipped with an N_2O measurement sensor. Thus, it is not clear what portion of NO_2 was converted N_2. However, it should be pointed out that more than 60% of NO_2 reduction further than NO at 100 °C with the space velocity of about 6,000 h^{-1} is possible with the combination of the Pt catalyst and the methanol reducing agent.

5. Pilot-scale Test

The first set of catalysts tested in the pilot-scale unit was composed of four 1,125 cm^3-sized honeycomb type catalysts with the cell density of 200 cpi (dimension: 15 cm×15 cm×5 cm). Total volume of the catalyst was 4,500 cm^3. The Pt loading on alumina washcoat was 0.22% based on the total weight of the catalyst. The gas turbine power output was adjusted at 40 MW (a half of full power output) and the exhaust gas from the stack showed a yellow color. The composition of the gas turbine exhaust gas diverted to enter the decolorization reactor was 14 ppm of NO, 22 ppm of NO_2, 470 ppm of CO, 2% of CO_2, 18% of O_2, 4% of H_2O (estimated) with N_2 balance. The temperature of the inlet gas without heating was between 120 °C and 130 °C. In some cases, the regulated electricity was applied to the electrical heater so that the inlet gas temperature was increased up to 249 °C. The NO_2 reduction test was carried out with or without the methanol addition. The rate of methanol injection was 3 cm^3/min, which corresponds to the molar ratio of methanol/NO_2 to be 14.5 and 11.1 for the GHSV of 70,000 h^{-1} and 92,000 h^{-1}, respectively. In the case of no methanol injection, the inherent CO in the exhaust gas acted as the reductant. Table 1 lists the NO_2 reduction performance of the 0.22 wt% Pt catalyst.

At the exhaust gas temperature of 127 °C, 77% of NO_2 was converted to NO even without the methanol injection. At the same time, 23% of CO was converted to CO_2, indicating CO was acting as the reductant. When methanol was added to the gas stream at 122 °C, the NO_2 conversion was 64%. In this case a portion of NO_2 was reduced further than NO. However, the CO conversion was only 9.4%, suggesting that methanol oxidation and CO oxidation share the same catalytic sites. It is expected from the lab-scale test that the 0.22 wt% Pt catalyst can reduce NO_2 much more than 70% at temperatures of about 120 °C (Fig. 5). However, considering 5.7 times larger space velocity of the pilot test than that of the lab-scale run, only 64 to 77% of NO_2 conversion at temperatures of about 120 °C can be attributed to high space velocities.

As the inlet gas temperature was increased to 220 °C or higher, the NO_2 conversion became larger than 95% and the outlet gas stream contained NO_2 less than or equal to 1 ppm. At the same time, the CO conversion was also increased from 69.4% at 220 °C to 92.3% at 240 °C. Especially at 249 °C, CO present in the gas stream was able to reduce NO_2 to completely NO, indicating that the injection of the methanol reductant was not necessary to reduce NO_2 if there was enough CO in the exhaust gas.

Another set of the pilot-scale experiment was carried out with a higher loading Pt catalyst, intending to achieve the high NO_2 conversion at the gas turbine exhaust temperature of about 120 °C. The second set of the catalyst was prepared by the Korean catalyst manufacturer (General System Co.). The amount of alumina washcoated was 20% of the weight of the ceramic monolith (400 cpi, dimension: 15 cm×15 cm×10 cm). Platinum loading was 0.27% of the total weight of the catalyst. The volume of totally four pieces of the catalyst was 9,000 cm^3. Again, the gas turbine's power output was set at 40 MW and the composition of the exhaust gas for this run was 14-15 ppm of NO, 21-27 ppm of NO_2, 445-460 ppm of CO, 2.6% of CO_2, 18% of O_2, 5% of H_2O (estimated) and with N_2 balance. The temperature of the inlet gas was between 102 and 124 °C.

Table 1. Change in NO_2, NOx and CO concentration over 0.22 wt% Pt catalyst with or without methanol injection (catalyst volume: 4,500 cm^3)

Temperature (°C)	Inlet	127	122	220	230	235	240	249
Space velocity (h^{-1})		70,000	70,000	92,000	92,000	92,000	92,000	92,000
Methanol (cm^3/min)		0	3	3	3	3	3	0
NO (ppm)	14	33	16	36	35	36	36	33
NO_2 (ppm)	22	5	8	1	1	0	0	0
NO_x (ppm)	36	38	24	37	36	36	36	33
CO (ppm)	470	363	426	144	100	52	36	41
NO_2 conversion (%)		77.3	63.6	95.5	95.5	100	100	100
NO_x conversion (%)		-5.6	33.3	0	0	0	0	8.3
CO conversion (%)		22.7	9.4	69.4	78.7	88.9	92.3	91.3

Table 2. Change in NO_2, NO, and CO conversion over 0.27 wt% Pt catalyst at different space velocities (catalyst volume: 9,000 cm^3)

Space velocity (h^{-1})	28,000	60,000	95,000
Temperature (°C)	102	117	123
NO_2 conversion (%)	96	96	96
NO_x conversion (%)	0	0	0
CO conversion (%)	87	84	71

Table 3. Change in NO_2 and CO conversion over 0.27 wt% Pt catalyst at different inlet temperatures (space velocity: 28,000 h^{-1} and catalyst volume: 9,000 cm^3)

Temperature (°C)	102	116	148	175	192
NO_2 conversion (%)	96	96	96	92	88
CO conversion (%)	87	85	92	95	96

No additional reductant was injected.

Table 2 lists results of NO_2 reduction over the 0.27 wt% Pt catalyst with varying space velocities at the exhaust gas temperatures of 102 °C to 123 °C. In this experiment the concentrations of NO_2 and CO fluctuated to a certain degree. Thus, each conversion was calculated based on the difference between the inlet gas concentration and the reactor exit concentration at the time of the measurement. As shown in Table 2, more than 95% of NO_2 is reduced over all the space velocities tested ranging between 28,000 h^{-1} and 95,000 h^{-1}. The concentration of NO_2 at the exit of the reactor was 1 ppm in all cases. A space velocity higher than 95,000 h^{-1} was not able to be obtained because the capacity of the blower was limited to supply the maximum gas flow rate of 853 m^3/hr. Again, the conversion of NOx being zero means that all of NO_2 was converted to NO. Meanwhile, CO conversion decreased as the space velocity increased, suggesting that the CO oxidation activity of the catalyst is not high enough at those temperatures.

The effect of the inlet gas temperature on the NO_2 and CO conversion can be found in Table 3. Similar to the behavior of the 0.33 wt% Pt catalyst at the lab-scale unit shown in Fig. 5, the NO_2 conversion started to decrease at temperatures higher than 175 °C over the 0.27% Pt catalyst at the pilot-scale test. Again, oxidation of CO was almost complete at those temperatures and oxidation of NO to NO_2 seemed to take place.

CONCLUSION

The catalytic NO_2 reduction process of the present study was very effective in decolorizing yellow-colored exhaust gases containing NO_2 at a wide range of temperatures from 70 °C to 360 °C, by just employing Pt catalysts with the different composition and the inherent CO in the exhaust gas. Its effectiveness was verified in a pilot-scale test utilizing the real gas turbine exhaust gas with 96% conversion of NO_2 at the exhaust gas temperature of about 110 °C. For the sole purpose of decolorization, the present process has advantages over conventional SCR or NSCR processes in that it operates at exhaust gas temperatures obviating additional heating/cooling devices and the corresponding operating costs. Moreover, the process can be operated with hydrocarbon or alcohol reducing agents. Although expensive platinum is used as the catalyst, more than 96% conversion of NO_2 at the space velocity of 95,000 h^{-1} requires a smaller amount of the catalyst. NO_2 was reduced only to NO at space velocities higher than 12,500 h^{-1}. However, there is a potential that this catalytic process can reduce NO_2 further than NO at lower space velocities and at temperatures as low as 100 °C.

ACKNOWLEDGEMENT

The financial support of this project was provided by Korea Electric Power Research Institute. General System Co. is greatly appreciated for manufacturing the catalyst for the pilot test.

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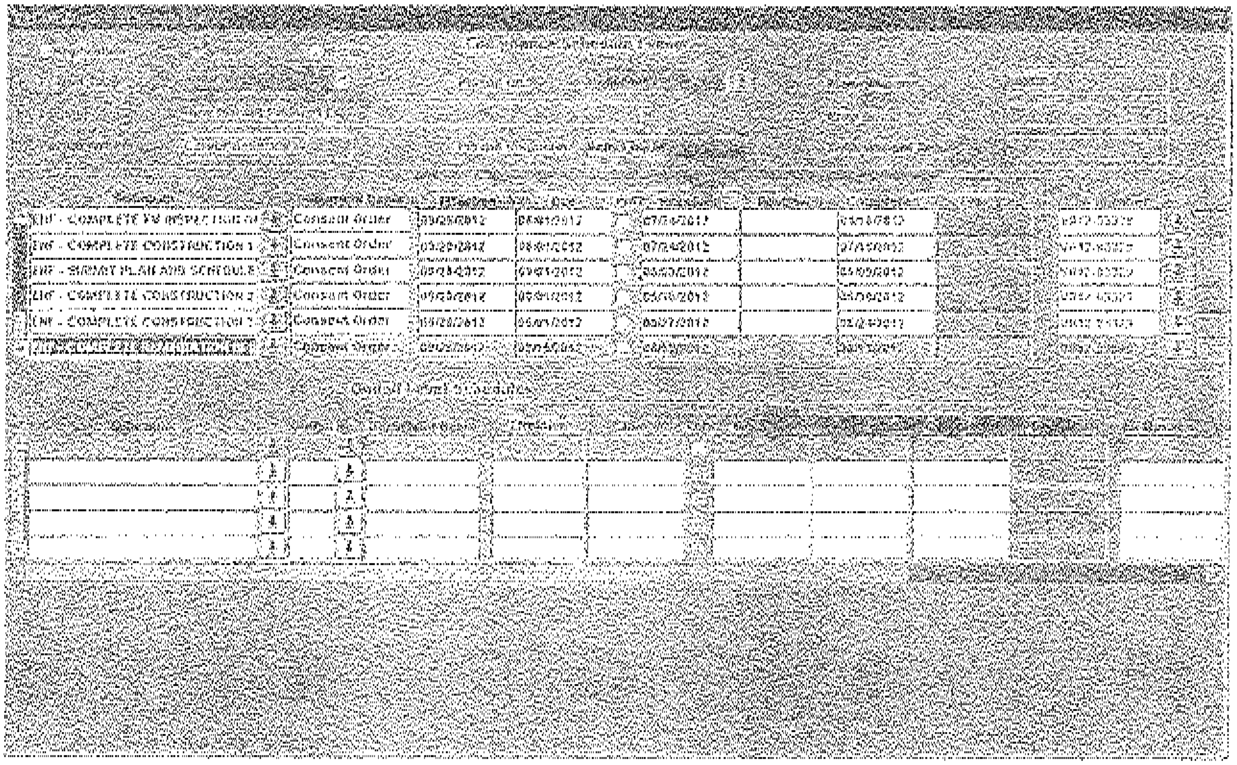
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Consent Order
Control Level Schedules

Attachment C

RBLC Data Table for Carbon Monoxide BACT

RBLC ID	NAME	UNIT CAPACITY	PERMIT ISSUANCE DATE	PROCESS NAME	CONTROL METHOD	EMISSION LIMIT		NOTE
						CO	VOC	
AR-0094	JOHN W. TURK JR. POWER PLANT	555.0 MMBtu/hr	11/05/2008	AUXILIARY BOILER	NONE	0.036 LB/MMBTU (see note)	0.0055 LB/MMBTU	CO: 30 DAY ROLLING AVERAGE; BACT LIMIT WAS 400 PPM AT 3% O2. 112(G) CASE BY CASE PERMIT LOWERED THIS T' 0.036 LB/MMBT\ VOC: 3-HR AVG
CA-1179	VENOCO-ELLWOOD ONSHORE FACLITY	35000 MMBtu	04/18/2011	Enclosed Thermal Oxidizer	Burner design, forced air blower, temperature controller	0.1 LB/MMBTU	0.0027 LB/MMBTU	40 MINUTES
CT-0156	MONTVILLE POWER LLC	995.00 MMBtu/hr	04/06/2010	82 MW Utility Boiler	Oxidation Catalyst	0.084 LB/MMBTU	5.5000 LB/H	
*FL-0330	PORT DOLPHIN ENERGY LLC	2 - 11,400 kW dual fuel Wartsila engines and 1 - 5700 kW dual fuel Wartsila engine.	12/01/2011	Power Generator Engines (3)	Catalytic Oxidation	0.165 G/KW-H (equals 0.11 Lb/MMBtu)	0.1500 G/KW-H (equals 0.097 lb/MMBtu)	3-HOUR ROLLIN' AVERAGE

RBLC ID	NAME	UNIT CAPACITY	PERMIT ISSUANCE DATE	PROCESS NAME	CONTROL METHOD	EMISSION LIMIT		NOTE
*FL-0334	ANCLOTE POWER GENERATING FACILITY	5500 MMBtu/hr each	09/14/2012	Fossil Fuel Fired Steam Generators	For Units 1 and 2, the applicant shall incorporate combustion controls based on good combustion practices for CO and NOX including, but not limited to, combustion by air staging achieved by close coupled overfire air (CCOFA).	0.15 LB/MMBTU	N/A	30-OPERATING DAY ROLLING AVERAGE
LA-0227	CLECO RODEMACHER POWER STATION	5445.00 MMBTU/H	05/08/2008	UNIT 2 BOILER (1-74)	LOW NOX BURNERS, OVERFIRE AIR, GOOD COMBUSTION PRACTICES	3000 LB/H (equals 0.55 Lb/MMBtu)	N/A	HOUR
LA-0231	LAKE CHARLES GASIFICATION FACILITY	938.30 MMBTU/H	06/22/2009	AUXILIARY BOILER	GOOD DESIGN AND PROPER OPERATION	33.78 LB/H (equals 0.036 Lb/MMBtu)	N/A	MAXIMUM
LA-0238	ALLIANCE REFINERY	831.30 MMBTU/H EACH	07/10/2009	CO BOILERS (2)	EQUIPPED WITH CORTOMETRIC HIGH INTENSITY COMBUSTION UNITS	379.1 LB/H (equals 0.46 Lb/MMBtu)	N/A	HOURLY MAXIMUM
LA-0245	HYDROGEN PLANT	1055.00 MMBTU/H	12/15/2010	SMR Heaters (EQT0400 and EQT0401)	Proper equipment designs and operations, good combustion practices	0.08 LB/MMBTU	0.0054 LB/MMBTU; 5.6900 LB/H HOURLY MAXIMUM (EACH UNIT)	

Attachment C

Emission Calculations: Units 001 and 002
(Reg. No. 40199 – Bremo Title V)

Emission Units 001 and 002

Actual emissions from the operation of units 001 and 002 will be calculated using the following equation:

$$E = F \times O$$

Where:

E = Emission rate (lb/time period)

F = Pollutant specific emission factors provided below

O = Rated capacity of the unit (1000 gal/hr or mmBTU/hr)

Emission Factors for Unit 001

Emission Unit 001		
Pollutant	**LPG (lb/1000 gal)**	**Distillate Oil (lb/1000 gal)**
PM/PM-10	0.6	3.3
SO_2	1.5	71

Emission Factors for Unit 002

Emission Unit 002		
Pollutant	**Distillate Oil (lb/MMBtu)**	**Kerosene (lb/MMBtu)**
PM/PM-10	0.31	0.012
SO_2	0.29	0.505

INDUSTRIAL BOILER WORKSHEET

CRITERIA POLLUTANTS

Source Name: Dominion Bremo
Registration #: 40199
Boiler Capacity: 8.7 million BTU/hr

THROUGHPUTS	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
per hour	0 gal	0 gal	0 gal	63 gal	0 gal	0 mcf	95 gal
per year	0 gal	0 gal	0 gal	551,817 gal	0 gal	0 mcf	832,248 gal
max. allow. / yr	507,671 gal	521,580 gal	528,824 gal	551,817 gal	568,289 gal	73,647 mcf	832,248 gal
Hours/yr	0	0	0	8760	0	0	8760

EMISSION FACTORS:

FUEL:	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
UNITS:	(<<---------	------lb/1000 gallons			------->>)	(lb/MMft3)	lb/1000 gallons
SCC#:	10200401	10200404	10200504	10200501	10200501	10200602	10201002
SULFUR	0.5 %	0.5 %	0.5 %	0.5 %	0.5 %	0 %	15 gr/10
Heat Content	150,000 BTU/gal	146,000 BTU/gal	144,000 BTU/gal	138,000 BTU/gal	134,000 BTU/gal	1,034 BTU/ft3	91,500 BTU/gal

Emission Factors	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
PM (filterable)	9.19 (a) S +3.22 (a)	10 (a)	7 (a)	2 (a)	2 (a)	1.9 (g)	0.2 (h)
PM (condensible)	1.5 (b)	1.5 (b)	1.5 (b)	1.3 (b)	1.3 (b)	5.7 (g)	0.5 (h)
PM10	8.03 (d) S +2.65 (d)	8.60 (d)	6.02 (d)	1 (e)	1 (e)	7.6 (g*)	0.7 (h)
PM2.5	5.23 (d) S +1.73 (d)	5.60 (d)	3.92 (d)	0.25 (e)	0.25 (e)	7.6 (g*)	0.7 (h*)
SO2	157 (a) S	157 (a) S	150 (a) S	142 (a) S	142 (a) S	0.6 (g)	0.1 (h) S
CO	5 (a)	5 (a)	5 (a)	5 (a)	5 (a)	84 (f)	7.5 (h)
NOx	55 (a)	55 (a)	20 (a)	20 (a)	20 (a)	100 (f)	13 (h)
VOC	0.28 (c)	0.28 (c)	0.20 (c)	0.20 (c)	0.20 (c)	5.5 (g)	0.8 (h)

LEAD is included on HAPs worksheet

EMISSIONS, UNCONTROLLED & PREDICTED: max hourly and expected annual

LB/HR	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
PM (filterable)	0.00	0.00	0.00	0.13	0.00	0.00	0.02
PM (condensible)	0.00	0.00	0.00	0.08	0.00	0.00	0.05
PM10	0.00	0.00	0.00	0.06	0.00	0.00	0.07
PM2.5	0.00	0.00	0.00	0.02	0.00	0.00	0.07
SO2	0.00	0.00	0.00	4.47	0.00	0.00	0.14
CO	0.00	0.00	0.00	0.31	0.00	0.00	0.71
NOx	0.00	0.00	0.00	1.26	0.00	0.00	1.24
VOC	0.00	0.00	0.00	0.01	0.00	0.00	0.08

LEAD is included as a HAP

TN/YR	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
PM (filterable)	0.00	0.00	0.00	0.55	0.00	0.00	0.08
PM (condensible)	0.00	0.00	0.00	0.36	0.00	0.00	0.21
PM10	0.00	0.00	0.00	0.28	0.00	0.00	0.29
PM2.5	0.00	0.00	0.00	0.07	0.00	0.00	0.29
SO2	0.00	0.00	0.00	19.59	0.00	0.00	0.62
CO	0.00	0.00	0.00	1.38	0.00	0.00	3.12
NOx	0.00	0.00	0.00	5.52	0.00	0.00	5.41
VOC	0.00	0.00	0.00	0.06	0.00	0.00	0.33

LEAD is included as a HAP

SUGGESTED PERMIT LIMITS:
uncontrolled pollutants
< 0.5 tn/yr not listed

	lb/hr	tons/yr
PM (Total)	0.21	1.20
PM10	0.07	0.57
PM2.5	--	--
SO2	4.47	20.21
CO	0.71	4.50
NOx	1.26	10.93
VOC	--	--
LEAD is included as a HAP		

NOTES:

(a) Table 1.3-1 (9/98)
(b) Table 1.3-2 (9/98)
(c) Table 1.3-3 (9/98)
(d) Table 1.3-5 (9/98)
(e) Table 1.3-6 (9/98)
(f) Table 1.4-1 (7/98)
(g) Table 1.4-2 (7/98)
(g*) Estimate from Table 1.4-2 (7/98)
(h) Table 1.5-1 (7/08)
(h*) Estimate from Table 1.5-1 (10/96)

INDUSTRIAL BOILER WORKSHEET

Source Name: Dominion Bremo

Registration #: 40199

Boiler Capacity: 8.693 million BTU/hr

HAZARDOUS AIR POLLUTANTS

(See Notes & Exemptions Info Below)

(See 9 VAC 5-60-300 C.7 for exemption to Toxics Regulation for certain boilers)

THROUGHPUTS	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
per hour	0 gal	0 gal	0 gal	63 gal	0 gal	0 mcf	95 gal
per year	0 gal	0 gal	0 gal	551,817 gal	0 gal	0 mcf	832,248 gal
Hours/yr	0	0	0	8760	0	0	8760

EMISSION FACTORS:

FUEL:	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
UNITS:	(<<----------	------- lb/1000 gallons	---------->>)	(<<----lbs/10^12 Btu	---->>)	lbs/10^6 cu ft	lbs/10^12 Btu
SCC#:	10200401	10200404	10200504	10200501	10200501	10200602	10201002
Heat Content	150,000 BTU/gal	146,000 BTU/gal	144,000 BTU/gal	138,000 BTU/gal	134,000 BTU/gal	1,034 BTU/ft3	91,500 BTU/gal

Emission Factors — Only Lead and HAPs from Exemption Note listed (See Note Below)

	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
Lead	1.51E-03 (1)	1.51E-03 (1)	1.51E-03 (1)	9 (3)	9 (3)	5.00E-04 (5)	4.84E-01 (5*)
Beryllium	2.78E-05 (1)	2.78E-05 (1)	2.78E-05 (1)	3 (3)	3 (3)	1.20E-05 (6)	1.16E-02 (6*)
Cobalt	6.02E-03 (1)	6.02E-03 (1)	6.02E-03 (1)			8.40E-05 (6)	8.14E-02 (6*)
Nickel	8.45E-02 (1)	8.45E-02 (1)	8.45E-02 (1)	3 (3)	3 (3)	2.10E-03 (6)	2.03E+00 (6*)
Phosphorous	9.46E-03 (1)	9.46E-03 (1)	9.46E-03 (1)				
Formaldehyde	6.10E-02 (2)	6.10E-02 (2)	6.10E-02 (2)	6.10E-02 (2)*	6.10E-02 (2)*	7.50E-02 (7)	7.27E+01 (7*)

* lb/kgal

EMISSIONS, UNCONTROLLED & PREDICTED: max hourly and expected annual

LB/HR	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
Lead	0.00E+00	0.00E+00	0.00E+00	7.82E-05	0.00E+00	0.00E+00	4.21E-06
Beryllium	0.00E+00	0.00E+00	0.00E+00	2.61E-05	0.00E+00	0.00E+00	1.01E-07
Cobalt	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.08E-07
Nickel	0.00E+00	0.00E+00	0.00E+00	2.61E-05	0.00E+00	0.00E+00	1.77E-05
Phosphorous	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Formaldehyde	0.00E+00	0.00E+00	0.00E+00	3.84E-03	0.00E+00	0.00E+00	6.32E-04

TN/YR	#6 OIL	#5 OIL	#4 OIL	#2 OIL	#1 OIL	GAS	LPG
Lead	0.00E+00	0.00E+00	0.00E+00	3.43E-04	0.00E+00	0.00E+00	1.84E-05
Beryllium	0.00E+00	0.00E+00	0.00E+00	1.14E-04	0.00E+00	0.00E+00	4.43E-07
Cobalt	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.10E-06
Nickel	0.00E+00	0.00E+00	0.00E+00	1.14E-04	0.00E+00	0.00E+00	7.75E-05
Phosphorous	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Formaldehyde	0.00E+00	0.00E+00	0.00E+00	1.68E-02	0.00E+00	0.00E+00	2.77E-03

SUGGESTED PERMIT LIMITS: same as uncontrolled per toxics policy

	LB/HR Exemption	TN/YR Exemption	Exempt ?	LB/HR	TN/YR
Lead	0.00990	0.02175	YES	--	--
Beryllium	0.00013	0.00029	YES	--	--
Cobalt	0.00330	0.00725	YES	--	--
Nickel	0.06600	0.14500	YES	--	--
Phosphorous	0.00660	0.01450	YES	--	--
Formaldehyde	0.08250	0.17400	YES	--	--

NOTES:

(1) Table 1.3-11 (9/98)
(2) Table 1.3-8 (9/98)
(3) Table 1.3-10 (9/98)
(4) Table 1.3-9 (9/98)
(5) Table 1.4-2 (7/98)
(6) Table 1.4-4 (7/98)
(7) Table 1.4-3 (7/98)
(5*) Table 1.4-2 (7/98) -- Converted NG factors to lb/10^12 Btus
(6*) Table 1.4-4 (7/98) -- Converted NG factors to lb/10^12 Btus
(7*) Table 1.4-3 (7/98) -- Converted NG factors to lb/10^12 Btus

Exemptions:

The following are not exempt for the fuels listed at maximum of **100 MMBtu/hr & 8760 hrs:**

Beryllium	2,1	Hourly & Annual
Cobalt	6,5,4	Hourly & Annual
Nickel	6,5,4	Annual
Phosphorous	6,5,4	Annual
Formaldehyde	6,5,4,2,1	Annual

All other HAPs with AP-42 factors are exempt at maximum throughp

Attachment D

Title IV Acid Rain Permit Application
And the CAIR Renewal Application
(Reg. No. 40199 – Bremo Title V)

Dominion Resources Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060
Web Address: www.dom.com

Dominion®

BY U.S. MAIL, RETURN RECEIPT REQUESTED

DEQ VALLEY

JUN 2 8 2012

To:

Date:

June 21, 2012

Mr. Janardan Pandey
Air Permit Manager
Virginia Department of Environmental Quality
Valley Regional Office
PO Box 3000
Harrisonburg, VA 22801

RE: Title IV Acid Rain Permit, Phase II NO_x Compliance Plan, and Phase II NO_x Averaging Plan Renewals, Bremo Power Station, DEQ Air Reg. No. 40199

Dear Mr. Pandey:

A Phase II Acid Rain Permit Application for the renewal of the Acid Rain Permit for Bremo Power Station is enclosed. The renewal forms for the Phase II NO_x Compliance Plan and a revised Phase II NO_x Averaging Plan are also enclosed.

Please contact Andy Gates at (804) 273-2950 if you need any additional information.

Sincerely,

Kenneth W. Roller

for Cathy C. Taylor,
Director, Electric Environmental Services

Enclosures

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☒ for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Bremo Power Station	VA	3796

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

DEQ VALLEY
JUN 2 8 2012
To:
Date:

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
3	Yes
4	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.

(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:

(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and

(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:

(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

STEP 3, Cont'd.

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

Effect on Other Authorities, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements
under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **C. D. Holley**	
Signature C D Holley	Date 06/04/2012

DEQ VALLEY

JUN . . . 12

To:

Date:

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Phase II NO_x Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is: [ ] New [X] Revised

STEP 1
Indicate plant name, State, and ORIS code from NADB, if applicable

Plant Name	State	ORIS Code
Dominion - Bremo Power Station	VA	3796

STEP 2

Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.

	ID# 3	ID# 4	ID#	ID#	ID#	ID#
	Type DBW	Type DBW	Type	Type	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(j) NO_x Averaging Plan (include NO_x Averaging form)	[X]	[X]	[ ]	[ ]	[ ]	[ ]
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging form)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

DEQ VALLEY

To:

Plant Name (from Step 1) **Dominion - Bremo Power Station**

STEP 2, cont'd.

	ID# 3 Type DBW	ID# 4 Type DBW	ID# Type	ID# Type	ID# Type	ID# Type
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17(a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign &

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).
Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.
Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **C.D. Holley**

Signature C.D. Holley | Date **6/21/2012**

DEQ VALLEY
JUN 28 2012
To:

EPA

Phase II NO_x Averaging Plan

For more information, see instructions and refer to 40 CFR 76.11

This submission is: ☐ New **X** Revised

STEP 1

Identify the units participating in this averaging plan by plant name, State, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation (ACEL) in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) ACEL	(c) Annual Heat Input Limit
Bremo Power Station (3796)	VA	3	0.46	0.80	1,447,000
Bremo Power Station (3796)	VA	4	0.46	0.46	1,059,000
Chesapeake Energy Center (3803)	VA	1	0.40	0.65	2,183,000
Chesapeake Energy Center (3803)	VA	2	0.40	0.65	2,225,000
Chesapeake Energy Center (3803)	VA	3	0.46	0.40	6,616,000
Chesapeake Energy Center (3803)	VA	4	0.40	0.40	2,812,000

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.39	≤	0.41

$$\frac{\sum_{i=1}^{n} (R_{Li} \times HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} (R_{li} \times HI_i)}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emission limitation for unit i, in lb/mmBtu, as specified in column (b) of Step 1;

R_{li} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

DEQ VALLEY

JUN 28 2012

To:

Plant Name (from Step 1) **Bremo Power Station**

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year ___________ through calendar year ______________ unless notification to terminate the plan is given.

☒ Treat this plan as 5 identical plans, each effective for one calendar year for the following calendar years: 2013 , 2014 , 2015 , 2016 and 2017 unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,
(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **C. D. Holley**	
Signature *CD Holley*	Date **6/21/2012**

DEQ VALLEY

JUN 2 ? 2012

To: ____________

Date:

Plant Name (from Step 1) **Bremo Power Station**

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Chesterfield Power Station (3797)	VA	3	0.40	0.55	3,219,000
Chesterfield Power Station (3797)	VA	4	0.40	0.25	2,210,000
Chesterfield Power Station (3797)	VA	5	0.40	0.25	5,327,000
Chesterfield Power Station (3797)	VA	6	0.40	0.25	16,711,000
Clover Power Station (7213)	VA	1	0.40	0.35	13,490,000
Clover Power Station (7213)	VA	2	0.40	0.35	17,318,000
Possum Point Power Station (3804)	VA	3	0.40	0.35	270,000
Possum Point Power Station (3804)	VA	4	0.40	0.35	625,000
Yorktown Power Station (3809)	VA	1	0.40	0.60	4,324,000
Yorktown Power Station (3809)	VA	2	0.40	0.60	4,269,000

DEQ VALLEY

JUN [illegible] 2012

To:

Date:

Dominion Resources Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060
Web Address: www.dom.com

Dominion®

VIA CERTIFIED MAIL

DEQ-VALLEY
JUN 13 2012
TO:
FILE:

June 11, 2012

Mr. Janardan Pandey
Air Permit Manager
Valley Regional Office
Virginia Department of Environmental Quality
PO Box 3000
Harrisonburg, VA 22801

RE: CAIR Renewal Application for the Bremo Power Station, DEQ Air Reg. No. 40199

Dear Mr. Pandey:

The application for the renewal of the CAIR permit for the Bremo Power Station located in Fluvanna County is enclosed. The current CAIR permit expires with the facility's Title V permit on December 31, 2012.

If you have any questions regarding the application, please call Mr. Andy Gates at (804) 273-2950.

Sincerely,

Cathy C. Taylor

Cathy C. Taylor
Director, Electric Environmental Services

Enclosure

CAIR Permit Application

(for sources covered under a CAIR SIP)

For more information, refer to 40 CFR 96.121, 96.122, 96.221, 96.222, 96.321, and 96.322

This submission is: ☐ New x Revised

STEP 1
Identify the source by plant name, State, and ORIS or facility code

Plant Name Dominion – Bremo Power Station State VA ORIS/Facility Code 3796

STEP 2
Enter the unit ID# for each CAIR unit and indicate to which CAIR programs each unit is subject (by placing an "X" in the column)

Unit ID#	NO_X Annual	SO_2	NO_X Ozone Season
3	X	X	X
4	X	X	X

DEQ-VALLEY
JUN 18 2012
TO:
FILE:

STEP 3
Read the standard requirements and the certification, enter the name of the CAIR designated representative, and sign and date

Standard Requirements

(a) Permit Requirements.

(1) The CAIR designated representative of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.122, §96.222, and §96.322 (as applicable) in accordance with the deadlines specified in §96.121, §96.221, and §96.321 (as applicable); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC, CCC, and CCCC (as applicable) of 40 CFR part 96 for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart II, III, and IIII (as applicable) of 40 CFR part 96, the owners and operators of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) that is not otherwise required to have a title V operating permit and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CC, CCC, and CCCC (as applicable) of 40 CFR part 96 for such CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and such CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable).

STEP 3, continued

(b) Monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96.

(2) The emissions measurements recorded and reported in accordance with subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96 shall be used to determine compliance by each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) with the CAIR NO_X emissions limitation, CAIR SO_2 emissions limitation, and CAIR NO_X Ozone Season emissions limitation (as applicable) under paragraph (c) of §96.106, §96.206, and §96.306 (as applicable).

(c) Nitrogen oxides emissions requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under §96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with subpart HH of 40 CFR part 96.

(2) A CAIR NO_X unit shall be subject to the requirements under paragraph (c)(1) of §96.106 for the control period starting on the later of January 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.170(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR NO_X allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.106, for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(4) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Allowance Tracking System accounts in accordance with subparts FF, GG, and II of 40 CFR part 96.

(5) A CAIR NO_X allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Annual Trading Program. No provision of the CAIR NO_X Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_X allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR NO_X unit.

Sulfur dioxide emission requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions for the control period under §96.254(a) and (b) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with subpart HHH of 40 CFR part 96.

(2) A CAIR SO_2 unit shall be subject to the requirements under paragraph (c)(1) of §96.206 for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under §96.270(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.206, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(4) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of 40 CFR part 96.

(5) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.205 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR SO_2 allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR SO_2 unit.

Nitrogen oxides ozone season emissions requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under §96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with subpart HHHH of 40 CFR part 96.

(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of §96.306 for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.370(b)(1), (2), (3) or (7) and for each control period thereafter.

(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.306, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.

(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with subparts FFFF, GGGG, and IIII of 40 CFR part 96.

(5) A CAIR NO_X allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_X allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

STEP 3, continued

(d) Excess emissions requirements.

If a CAIR NO_X source emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation, then:

(1) The owners and operators of the source and each CAIR NO_X unit at the source shall surrender the CAIR NO_X allowances required for deduction under §96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

If a CAIR SO_2 source emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation, then:

(1) The owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under §96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

If a CAIR NO_X Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO_X Ozone Season emissions limitation, then:

(1) The owners and operators of the source and each CAIR NO_X Ozone Season unit at the source shall surrender the CAIR NO_X Ozone Season allowances required for deduction under §96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §96.113, §96.213, and §96.313 (as applicable) for the CAIR designated representative for the source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.113, §96.213, and §96.313 (as applicable) changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96, provided that to the extent that subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable).

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) or to demonstrate compliance with the requirements of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable).

(2) The CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source shall submit the reports required under the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) including those under subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96.

(f) Liability.

(1) Each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) shall meet the requirements of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable).

(2) Any provision of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) that applies to a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) or the CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) shall also apply to the owners and operators of such source and of the CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X Ozone Season units (as applicable) at the source.

(3) Any provision of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) that applies to a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) or the CAIR designated representative of a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) shall also apply to the owners and operators of such unit.

Plant Name (from Step 1) Dominion – Bremo Power Station

STEP 3, continued

(g) Effect on Other Authorities.
No provision of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable), a CAIR permit application, a CAIR permit, or an exemption under § 96.105, §96.205, and §96.305 (as applicable) shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) or CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

Certification

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name C. D. Holley	
Signature C D Holley	Date 06/04/2012